Systematic approach to numerical simulation and modelling of shale gas reservoirs

Amirmasoud Kalantari-Dahaghi
Department of Petroleum and Natural Gas Engineering, West Virginia University, Morgantown, West Virginia, 26506, USA
E-mail: akalanta@mix.wvu.edu

Abstract: With the rapid development of unconventional resources in the USA and its contribution by diminishing energy dependency on foreign supplies, reservoir simulation technology is facing new challenges in providing key information to be utilised for long-term development decisions. Therefore, growth in shale gas reservoir development necessitated new approach to reservoir simulation.

In this paper, simulation model formulations dealing with unique physics and flow mechanism within shale gas reservoirs have been discussed and more suitable simulation techniques have been devised with the intention of improving shale gas recovery.

Fractures have substantial effect on production from shale gas reservoirs. Complex DFNs were stochastically generated and up-scaled in order to simulate fluid flow through the system. Logarithmic local grid refinement was employed to model hydraulic fractures, while matrix discretisation technique with matrix subgrids was used to capture long transient fracture to matrix gas flow. History matched model was further used for studying enhanced shale gas recovery through CO₂ sequestration simulation. [Received: September 25, 2010; Accepted: December 20, 2010]

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Biographical notes: Amirmasoud Kalantari-Dahaghi received his MS in Petroleum and Natural Gas Engineering from West Virginia University in 2010. Currently, he is a PhD student in Petroleum and Natural Gas Engineering at West Virginia University. His current research interests include modelling and simulation of unconventional gas resources especially shale gas reservoirs, CO₂ sequestration, and real-time data analysis using artificial intelligence and data mining.
1 Introduction

Similar to conventional hydrocarbon systems, unconventional gas reservoirs are characterised by complex geological and petrophysical systems as well as heterogeneities – at all scales (Newsham and Rushing, 2001). However, unlike conventional reservoirs, unconventional gas reservoirs typically have very fine grain rock texture, exhibit gas storage and flow characteristics which are uniquely tied to nanoscale pore throat and pore size distribution and possess common organic and clay content that serve as gas sorption sites (Sondergeld et al., 2010). Gas shale reservoir pore structures are defined in terms of nanometres to micrometers, whereas, most tight gas reservoirs are described at a micrometer or larger scale. Both gas shale and tight gas systems have free gas stored within the pores of the rock matrix. Gas shale differs in possessing the characteristic of gas adsorption on surface areas associated with organic content and clay. Bustin et al. (2008) states that the relative importance of adsorbed versus free gas varies as a function of the amount of organic matter present, pore size distribution, mineralogy, diagenesis, rock texture and reservoir pressure and temperature. Gas shale reservoirs in the USA tend to be found within three-depth ranges between 250 and 8,000 ft. The New Albany and Antrim shales, e.g., have some 9,000 wells in the range of 250 to 2,000 ft. In the Appalachian basin shales and the Devonian and Lewis shales, there are about 20,000 wells from 3,000 to 5,000 ft. Although the Barnett and Woodford shales are much deeper, the Caney and Fayetteville shales are from 2,000 ft to 6,000 ft, with most of the reservoirs between 2,500 and 4,500 ft. A good shale gas prospect has a shale thickness between 300 and 600 ft. (Sondergeld et al., 2010)

Shale has such low permeability that it releases gas very slowly, which is why shale is the last major source of natural gas to be developed. Shale can hold a vast amount of natural gas. The most prolific shales are relatively flat, thick, and predictable, and the formations are so large that their wells will continue producing gas at a steady rate for decades.

Fractures are the key to good production. The more fractures in the shale around the wellbore, the faster the gas will be produced. Because of shale’s extremely low permeability, the best fracture treatments are those that expose as much of the shale as possible to the pressure drop that allows the gas to flow. The natural formation pressure of a large gas shale reservoir will decline only slightly over decades of production. Any pressure drop on individual wells is likely the result of fractures closing up, rather than depletion of the reservoir. The key to good shale gas production over time is having the proper distribution and placement of proppant to keep the fractures open.

1.1 Numerical modelling and operational challenges of shale reservoirs

A vibrant and fast-growing literature exists related to various aspects of gas shales, including operational (e.g., drilling, completion, and production) and technological challenges. The latter mainly involves difficulties in formation evaluation/characterisation, in modelling gas-matrix-fracture phenomena, and in developing reliable reservoir simulators.

In times, these studies directly point to difficulties in accurately predict the ultimate gas recovery and to explain high variability in gas well productivity, which are common to nearly all shale gas reservoirs.
One of the objectives of this paper is to trying to have a better understanding of the operational and modelling challenges associated with shale gas reservoirs, which have been proposed, by several operators and authors during the past several years. There is currently considerable focus on the reserve estimation, especially focusing on optimising the shale formation through advanced completion technology and numerical simulation. Applying conventional knowledge and methodologies to unconventional reservoirs can be a humbling experience. One of the primary drivers is the lack of reliable datasets during modelling to quantify risks and optimise well placement, completions and production.

Shale gas plays, which require maximum reservoir exposure to be economic, have been solved through the use of long horizontal wells that are fractured in multiple zones along their several-thousands feet length; therefore, horizontal completions are one of the key things that have led to all of the successes. Most producers have been working under the assumption that the reservoir changed little along the length of the horizontal. Each zone, therefore, was fractured identically. On the other hand, as detailed logging can reveal, the reservoir is not consistent, with qualities varying abruptly in vertical and lateral directions, and therefore each fracture should be designed specifically for each zone. Therefore, in order to optimise fractures in horizontal wells the first thing to understand is the heterogeneity of the reservoir along the lateral, how the properties are changing, which is contrary to what many people assume. So, in gas shale exploration small, often slight but fundamental, petrophysical differences result in larger differences in material properties that separate good quality reservoirs from bad quality ones. Overall, it requires the combined effort of specialists from various disciplines for developing a new methodology for successful exploration and production.

As a result, one of the main issues that remain is determination of the hydraulically induced fracture height containment within the shale reservoirs, as well as the shale stress variation in the lateral directions, to ensure the lateral is landed in the proper horizon and the perforations are made at the proper location.

The principle means to characterise the lateral have been open hole wire line logging – taking readings before the well has been cased and cemented. However, open-hole logging has its drawbacks. Since it requires the presence of a drilling rig, it adds to day rate costs and it can be risky. Given those limitations, evaluation within that horizontal has really been left out and it is extremely important to have this information. The trend in the industry has been to only conduct reservoir evaluation on the initial and vertical wells, and then apply this knowledge to the rest of the field. There are many recent instances where we are not entirely sure of the stress environment that we are in while completing some of these wells, and this has led to ineffective well stimulation. Oftentimes, a re-fracturing is required which creates additional expense (Smith, 2009).

Understanding reservoir properties like lithology, porosity, organic carbon, water saturation and mechanical properties of the rock, which includes stresses, beforehand and planning completions based on that knowledge is the key to production optimisation. Therefore, the final objective is to increase our ability to integrate proprietary laboratory and petrophysical measurements with geochemical geological, petrologic, and geomechanical knowledge, to develop a more solid understanding of shale plays and to provide better assessments, better predictions, and better models. There are still many problems to be solved and many challenges to overcome. These challenges make unconventional gas an exciting technical area.
In general, shale gas exploration and production have many requirements:

- Methods for handling multi scale heterogeneity and associated scaling relationships (sample-core, core-log, log-seismic).
- Knowledge of source-rock geochemistry, kerogen-rock interactions, and associate fluid-solid interactions.
- Understanding the drivers of reservoir quality and the potential for accessing high quality reservoir sections via hydraulic fracturing.
- Understanding fracture containment and the drivers of fracture complexity. Including the associated problems of proppant transport, water trapping, and resulting low fracture conductivity.

Numerical simulation is a powerful tool that integrates core, log, and well-test data to help quantify well behaviour by assessing the effects of variations in key reservoir parameters, incorporating unique components such as directional permeability and the contributions of free gas and sorbed gas, and evaluating the effects of various development strategies including well spacing, well pattern, and fracture-stimulation design. Once constructed, the model can be updated with production data, static reservoir pressures, and producing bottom-hole pressures obtained on a regular basis to better understand and predict future well performance.

In spite of tremendous effort and progress, the key factors that dominate reservoir production remain somewhat unclear, and a systematic approach is needed to integrate the variety of information and capture key elements. There is a current need for the development of appropriate mathematical models and numerical methods and appropriate gridding and upscaling techniques to assist engineers in the design of fracture treatments that are both economical and effective.

Modelling and simulation of shale gas reservoir is challenging due to complex nature, strong heterogeneous and anisotropic system, different reservoir behaviour, multiple gas-storage mechanisms and unique attributes that control productivity, which is vastly different from conventional reservoirs. Therefore, building a general workflow is critical in order to capture all aspects of shale characteristics and to obtain a clear understanding and an accurate description of the reservoir.

Advances in understanding these complexities over the past 20 years have been accompanied by substantial improvements in drilling, completion, and production technologies. The result is faster dewatering, earlier and higher peak gas rates, more-accurate resource and reserves estimates, and improved economics.

Kalantari et al (2009a, 2009b and 2011) proposed an unconventional way to model and simulate shale reservoirs by using artificial intelligence and data mining techniques. In this method an intelligent model which is capable of predicting future shale gas reservoir performance was developed.

2 Theoretical background

2.1 Theory behind shale gas modelling and simulation

Reservoir modelling is the most powerful tool available to fully integrate knowledge from multiple domains. Its foundation is a data-constrained model that simulates the
behaviour of the fluids, rock and drive mechanism within the shale reservoir. The 3D model is derived from geology, geophysics, petrophysics and engineering data and interpretations. The model can be used to predict and validate reservoir and field development plans such as operating conditions and different recovery methods. Reservoir modelling and simulation is a widely accepted technology to aid in the field development planning of ultralow permeability shale gas reservoirs. Since there are always more parameters to be estimated in the model compared with available data, there is always uncertainty. A reliable shale gas reservoir model is able to represent current production history while honouring all the input data. One of the most convincing ways to validate a reservoir model is comparison of the forecasts to actual field and well behaviour postdating the model predictions.

2.2 Natural fracture modelling

Understanding and modelling fracture corridors is the primary driver for successful development of naturally fractured shale reservoirs. This assumes further significance because shale is characterised by very low matrix porosity and permeability and the primary productivity of the reservoirs is purely dependent on the presence of natural fractures. Although in most shale plays, no open fractures were observed from the core in the laboratory, all borehole images such as FMI-interpreted fractures – resistive, partial-resistive and conductive – are subject to easier opening by hydraulic fracturing than virgin shale rock (Gale et al., 2007). Therefore, the role of natural fractures in the quality of the production and in the creation of the complex induced fracture network is also a key issue, as it is poorly understood. As a result, the modelling of natural fracturing in shale is a very important issue to be addressed in order to estimate properly the quality of any shale gas prospect.

In most of shale reservoirs, fracture complexity, which ensures the creation of large fracture surface areas needed for the production, requires a low stress contrast between the maximum horizontal principal stress and the minimum horizontal principal stress. The presence of natural fractures properly oriented with respect to the principal stress direction is also required to create this fracture complexity. One can argue they might also cause the fracture initiation pressure to decrease and are a high TOC indicator (Thiercelin et al., 2009).

Distribution and type of natural fractures are a function of palaeo and present day stress, structural elements, regional tectonics and the mechanical stratigraphy of the reservoirs involved. Direct detection of fractures is below the resolution of conventional seismic data. However, through a combination of seismic derived attributes like volume curvature integrated with well data, it is possible to better understand the distribution of fracture corridors for more successful field development.

Well and field-wide analysis of relationships between seismic derived attribute-pattern and fracture orientation and intensity from wells and relation with well productivity was established. The understanding of the relation between these two different sets of data has helped in using the fracture data from wells as hard data and seismic attribute volumes as soft constraint for building the 3D discrete fracture network (DFN) model representing the distribution of fracture porosity and permeability. The developed fracture model along with the matrix model were used by the reservoir engineers to dynamically history match and validate the model before using it for planning the field development.
One of the difficulties in DFN modelling is the fracture geometry and its distributions. Those parameters have to come from relevant and realistic geological studies.

Gale et al. (2007) have provided certain insight into this issue. Although it might be possible to obtain some references from a fracture intensity property, but the final estimation has to come from production history matching.

2.3 Fracture data analysis

The analysis of fluid transport in naturally fractured shale reservoirs requires detailed, often hard to obtain, information about the reservoir’s fracture network. The properties of the network that control flow within the reservoir include fracture orientation, relative abundance of different fracture sets, length, aperture, intersection frequency and fracture clustering (Hatzignatiou and McKoy, 2000). An accurate model of the reservoir fracture network can help to improve the efficiency of enhanced shale gas recovery and CO₂ sequestration operations.

At depth, detailed data can be gathered through core samples, FMI logs, and acoustic borehole televiewers. Fracture models developed from limited borehole observations can be extended into the surrounding area using 3D seismic data and well production (history) data (Hart and Balch, 2000). Core data and FMI logs provide information about fracture abundance, orientation, aperture, and spacing, with coverage limited to logged and cored intervals and also by the borehole diameter. The ability to extend borehole interpretations into the surrounding area is dependent on the number and distribution of wells that penetrate the reservoir of interest. The challenge is to extrapolate the extent and distribution of the fractures observed in the borehole into the surrounding strata.

Characterisation of fracture networks often begins with a geometric model portraying the cylindrical borehole intersecting a fracture represented by a circular plane (Özkaya, 2003). Using this approach, borehole intersections of multiple fractures can be used to estimate minimum fracture spacing. FMI data also provide a measure of fracture aperture. A relationship between fracture aperture and length (e.g., Vermilye and Scholz, 1995) is used to estimate fracture length distributions based on FMI aperture observations. These properties along with fracture orientation and relative abundance of different open fracture sets have to be incorporated into the fracture network model. Orientation and spacing data can be obtained from FMI logs as noted. In this study, outcrop observations are also used to validate network properties.

Fracture orientations and distributions can vary considerably depending on the lithology and deformation history of the rock. Stochastic fracture model generation is a critical step in the development of realistic simulation models. The validity of the starting model requires accurate approximation of the reservoir fracture network parameters. This helps ensure that variations in the properties of the fracture network required to match production history yield a realistic model consistent with the observations.

Statistical parameters describing bedding and fracture orientations, fracture aperture, and fracture density are used as basic inputs into Petrel’s fracture network generator to examine the influences of the shale fracture network on gas production and controlling of early breakthrough during enhanced shale gas recovery.

Data obtained from well logs characterise large-scale features in a relatively small volume of rock. These large-scale features have to be integrated with lower resolution seismic data across a large volume of reservoir.
2.4 Modelling fracture parameters

Fracture modelling is a multi-step process involving several disciplines within reservoir characterisation and simulation. The main idea is to build on geological concepts and gathered data such as interpretation of beds, faults and fractures from image log data, use field outcrop studies as analogues for conceptual models, seismic attributes used as fracture drivers, etc. The next step is to transfer this data into a description of fracture properties which can be populated into a 3D geological framework model. Depending on the analysis of the fracture data, multiple sets of fractures can be identified; these can be the result of different tectonic events, such as over-thrusts and extensional faults, conjugate fractures related to bending or flexure of geological layers, or simple joints related to difference in lithology.

Once data have been identified, analysed and categorised, the fracture model itself can be built. Using the initial properties description, the fracture properties have to be populated in the 3D grid stochastically or deterministically. If this is done deterministically, one needs to have a very good idea of where fractures are and how they behave in the 3D space. This could be done using high confidence fracture patches from the seismic volume attribute process, or an existing fault model.

If no such data exists, a stochastic method should be used.

2.5 Building a DFN model

A DFN is a group of planes representing fractures. Fractures of the same type, generated at the same time are grouped into a fracture set. Each fracture network has at least one fracture set but may have many of them. Fracture sets can typically be fractures analysed from image logs, separated by genetic events, orientation or other factors.

The development of a DFN for use in flow simulations is a multi-step process. Fracture network can be modelled deterministically using direct input or stochastically based on input statistics.

The fracture sets are created deterministically either as a result of fault plane extraction from seismic cube or as previously defined fractures. Fracture types that can serve as an input are: fault patches (fault plane extraction from a seismic cube), fault surfaces/polygons (converted from the faults in the 3D grid, fault points) and a previously defined DFN.

In stochastic DFN approach, fracture set will be modelled for the whole 3D grid, per region or within zones. Such a model requires three basic inputs: fracture distribution, geometry and orientation.

Stochastic fracture network can typically be fractures where location, size and orientation is not directly known, but can be inferred from statistics.

2.5.1 Fracture distribution

For modelling fracture distribution description has been used rather than the classification (fracture density index) that has been used by others like Dershowitz and Herda (1992), therefore, three-options can be used: number of fracture/volume, fracture length/volume, and fracture area/volume.

Fracture area/volume (referred to in the literature as P32) is scale independent (independent of orientation) and most used in 3D fracture modelling. In terms of fracture
spacing, the spacing is equal to 1/P\text{32}, assuming parallel fractures.

2.5.2 Fracture geometry

- **Shape**: In real life, the fracture has been conceptualised to be shaped as ellipses, but this representation requires a lot of computational power; therefore, the fracture shape is simplified to number of sides and an elongation ratio.
- **Length**: Defines the distribution of fracture length in the model and can be described using exponential, power-law, log-normal, normal or constant distributions with minimum and maximum cut offs. Cut off required for exponential and power law distributions and will define how much of the defined fracture intensity will be modelled explicitly in the fracture network.

2.5.3 Fracture orientation

Fracture orientation is often sparse data and modelling orientation across the reservoir is difficult. It could be supplied in the form of maps or properties of dip, azimuth, and concentration (maps can be converted to properties). Surfaces of, e.g., azimuth can be created by digitising polygons and making azimuth maps.

Orientation of fracture can be defined by mean dip, mean dip azimuth and concentration (Kappa factor) and can be modelled using three different distribution methods:

- **The Fisher model method**: describes a distribution of angles where the directions are not the fracture planes themselves, but the normal to the planes. These poles are scattered around a mean dip and azimuth based on concentration.
- **The Bingham model method**: describe an annular axisymmetric orientation distribution.
- **The Kent model method**: describes a distribution similar to Fisher, but deviation around the preferred direction is anisotropic.

2.5.4 Fracture aperture

Aperture is an uncertain parameter and calculating fracture aperture is a little more tedious and must be investigated for each reservoir, but can be measured from image logs or a constant value can be assigned, e.g., per fracture set. If not, aperture may be related to DFN fracture size/length. The fracture aperture is an indicator of the perpendicular width of an open fracture. The limitation is that wall roughness, gouge, mineral filling and lateral continuity are not captured; that is the aperture values are not quantitative. Hydraulic fracture aperture is a term which considering flow through only the open part of fracture; the flow is a function of the cube of aperture width.

2.6 Upscaling fracture attributes

A DFN model is made with some fracture network attributes, however, for practical purposes in dynamic reservoir models, these are not useful until they are up-scaled into the required grid dimensions that can be used for performing dual continuum (dual
porosity or dual porosity/dual permeability) flow simulation. The new grid properties are fracture permeability (either diagonal or full tensor), fracture porosity and shape factor (matrix-fracture exchange term).

*Sigma factor:* is a connection factor between the matrix and fracture properties, describing how fluid flows between matrix and fractures of a dual porosity/permeability model in porous medium. Interaction between the fracture surface and the shale matrix enables some drainage of the rock matrix. This interaction may increase the recoverable gas within the shale matrix. The numerically derived expression for sigma (shape) factor in terms of fracture spacing \( L \) in \( j, k \) and \( l \) grid coordinate directions of given cell is as follows:

\[
\sigma = 4 \left( \frac{1}{L_j} + \frac{1}{L_k} + \frac{1}{L_l} \right)
\]  

If, \( \sigma = 0 \) it means that there is no communication between matrix and fractures.

*Fracture porosity* is calculated simply by:

\[
\phi_f = \frac{\text{Aperture} \times \text{Area}}{\text{Volume}}
\]

Two-methods to up-scale the DFN properties in the grid include Oda and flow-based methods.

2.6.1 *ODA method (statistical)*

This method primarily relies on the geometry and distribution of fractures in each cell to build permeability tensor. It uses a statistical method based on the number and sizes of the fractures in each cell. It is fast but does not take into account the connectivity of fractures and can therefore underestimate fracture permeability when the intensity is low.

2.6.2 *Flow-based tensor up scaling*

It creates a finite element grid for each grid cell and uses finite element code to run three-small-scale flow simulations per coarse cell on the DFN. It is much slower, but provides accurate results. In this method, calculations are much slower than Oda method, but it takes into account the full geometry of the system.

2.7 *DFN with fracture drivers*

Fracture driver is a property in the entire grid that could provide some additional information on the lateral/spatial extent of fractures. It works as a guide for the 3D distribution of intensity. Fracture driver types are:

- geological drivers: porosity, facies, N/G, etc.
- seismic drivers: acoustic impedance, etc.
- geotechnical drivers: structural derivatives (curvature), fault-related, etc.
- stress-related drivers: stress, effective permeability from history match, etc.
2.8 Hydraulic fracture modelling

The recent development of horizontal drilling in shale gas reservoirs allowed producers to improve the amount of gas recovered significantly. Although horizontal wells cost twice as much as vertical wells but the EUR is three-times greater. Gas shale; however, need to be hydraulically stimulated to produce at economical rates.

A typical completion consists of drilling the lateral in the direction of the minimum principal stress, separating the lateral in several stages, and for each stage starting from the toe, perforating using two to four-perforation clusters and then stimulating. The stage is then isolated and the process continues.

Hydraulic fracture propagation is mainly controlled by combination of in situ stress, reservoir pressures, the rock matrix, and the natural fracture system. Therefore, the major concern in production from shale is the identification of hydraulic fracture growth and their interaction with the pre-existing natural fracture system. Therefore, identifying the natural fracture characteristics play an important role in successful hydraulic fracturing design even though in some shale plays some of natural fractures are mineral filled.

Signatures of natural and induced fractures are seismic anisotropy, its dependency on elastic load and pore pressure, and symmetry and dynamics of seismicity domains activated by hydraulic fracturing of such reservoirs. Two-latter features of fractures in shale gas reservoirs are of extremely non-linear character and insufficiently well understood.

A non-linear process is responsible for micro-seismicity triggering in shale. For example, microseismic features of hydraulic fracturing in Barnett shale correspond to non-linear pressure diffusion in a medium with permeability very strongly enhanced by fluid injection. It seems that the volumetric (possibly tensile) opening of preexisting fractures embedded into extremely impermeable compliant matrix is a dominant mechanism controlling the dynamics of the induced microseismicity there. This process can be denoted as a three-dimensional volumetric hydraulic fracturing.

A key problem is the embedment of proppants in the fracture faces. Fractures with proppant monolayers can close quickly during production but embedment and damage of the fracture faces likely occurs as a time-dependent process slowly reducing fracture conductivity.

In order to have better estimation of pressure profile around hydraulic fracture and model fractures explicitly, logarithmic local grid refinement techniques has employed which use unequal spacing in LGR to properly capture pressure transients. The finest grids represent the hydraulic fracture; the fracture conductivity (md-ft) can be calculated by multiplication of fracture permeability (md) and fracture width (ft). The dimensionless fracture conductivity correlation is as follows:

\[
F_{CD} = \frac{k_f w_f}{k_f X_f}
\]

where

- \(K_f\) fracture permeability
- \(w_f\) fracture width
- \(K\) formation permeability (pre stimulation)
- \(X_f\) fracture half-length.
2.9 Non-Darcy flow modelling

2.9.1 Non-Darcy flow near wellbore

A flow dependent contribution can be included to model non-Darcy effects in gas flow near the well (i.e., Turbulent flow due to high flow rates in and around fractures)

\[ S \rightarrow S + Dq_{fs} \]  

(3)

\( q_{fs} \) represents the flow rate of free gas through the connection. The \( D \)-factor is usually obtained from measurements on the well, and is multiplied by the well’s free gas flow rate \( Q_{fg} \) to give the non-Darcy contribution to the skin factor. Nevertheless, in reality the effect of non-Darcy flow at a connection depends on the free gas flow rate through the connection itself rather than the well as a whole. Accordingly, the non-Darcy skin from the connection flows is calculated using the above equation. If the well has more than one connection, the \( D \)-factor must be scaled to apply to the connection flows instead of the well flow.

The scaling process aims to give each connection initially the same non-Darcy skin, by setting the \( D \)-factors in inverse proportion to the gas flow rate. The calculation assumes that initially the free gas mobility and the drawdown are the same in each connection, so that:

\[ D_j = D_w \frac{\sum T_{wi}}{T_{wj}} \]  

(4)

where

- \( D_j \) is the scaled \( D \)-factor for the connection
- \( D_w \) is the measured \( D \)-factor for the well
- \( \sum T_{wi} \) term denotes the sum of the connection transmissibility factors for all the connections in the well that are open at the time the \( D \)-factor is specified.

2.9.2 Non-Darcy flow between cells (flow-dependent skin)

The treatment of non-Darcy effects in inter-block flow, and specifies the non-Darcy flow coefficient. This is commonly known as \( \beta \), the non-Darcy flow coefficient, and is entered in units of atm. \( s^2/g \) (the Forchheimer) in all unit sets.

\[ \frac{dP}{dx} = \left( \frac{\mu}{Kk_rA} \right) q + \beta \rho \left( \frac{q}{A} \right)^2 \]  

(5)

where

- \( q \) is the volumetric flow rate
- \( K \) is the rock permeability
- \( k_r \) is the relative permeability
- \( A \) is the area through which flow occurs
\( \mu \) is the fluid viscosity
\( \rho \) is the fluid density
\( \beta \) is the Forchheimer parameter
\( \frac{dP}{dx} \) is the pressure gradient normal to the area.

### 2.10 Volumetric fracture modelling technique

In this method instead of using LGR around hydraulic fractures the entire extent of stimulated zone is captured from microseismic and hydraulic fracture treatment parameters (e.g., amount of fluid pumped) are also taken into account, then the estimated productive volume from estimated stimulated volume (ESV) will be history matched. The uncertain parameter in this method during history matching process is 3D fracture shape instead of \( X_f \). This method is going to be used in future study. Figure 1 shows the productive and stimulated reservoir volume using microseismic.

**Figure 1**  Productive and stimulated reservoir volume (see online version for colours)

### 2.11 Shale gas flow simulation models

#### 2.11.1 Dual porosity model

A shale gas reservoir with shale rock and natural fracture can be typically modelled as a dual porosity system which proposed by Warren and Root. In this method fractured shale gas reservoir is considered as two-medias. One associated with fluid storage (matrix media) and the other with fluid transport (fracture media). Fluid flow through these porous media is radically different because the fractures have small bulk porosity and large permeability, while the matrix blocks have large bulk porosity and small permeability.

Warren and Root modelled the dual-porosity reservoirs as a set of ‘stacked sugar cubes’ imbedded in the fractured medium while Kazemi modelled the fractures as very thin horizontal planes separated by matrix layers. Kazemi et al. (1976) introduced the first two-phase, water-oil, numerical simulation model for the dual-porosity reservoirs. The fracture media was discretised as grid blocks and the fluid flow was simulated using
fracture mass-balance equations. Furthermore, the matrix media was assumed to act as
discrete source/sink terms in the fracture media, and the flow between fracture and matrix
was accounted by a matrix-fracture transfer term. This transfer coefficient is usually
represented by the variable sigma, \( \sigma \) that has been explained in natural fracture modelling
section of paper.

The flow in a numerical model between the grid blocks representing the fractures and
matrix material is calculated by a special transmissibility that involves this parameter. If
the fracture and matrix grid blocks are not adjacent in the numerical grid, then
non-neighbour connections are created in the simulators. So two-superimposed identical
grids, representing respectively the matrix and fracture media are created to discretise the
reservoir (Figure 2).

**Figure 2** Dual porosity numerical and conceptual model (see online version for colours)

![Figure 2](image1)

**Figure 3** Matrix discretisation-numerical and conceptual model (see online version for colours)

![Figure 3](image2)
2.11.2 Matrix discretisation model

Traditional dual porosity models assume that the matrix to fracture flow is in steady state, and thus, the matrix cell can be regarded as a single cell. In shale gas reservoirs, the flow is not instantaneous and requires matrix subdivision to capture transient nature of the matrix to fracture flow. Typically, shale gas reservoirs have multi porosity system (micro porosity, fractures and organic content).

To model these systems a discretised matrix model can be used, which subdivides each matrix cell into a series of nested sub-cells, allowing the simulator to predict the transient behaviour in shale matrix.

Subgrids are logarithmic away from the fracture wall. The matrix cells are only connected to their corresponding fracture cell, but flow to the matrix surface is supplied from a 1D grid system. The matrix subdivision can be setup by specifying the number of sub-cells that each matrix cell is going to be split into. The geometry of the subdivision (transmissibility) can be linear, radial (cylinder) or spherical (cubic) (Figure 3).

Dual porosity is required for shale, which means \( NZ \) must be twice the number of model layers. In matrix discretisation model (\( NMATRIX > 1 \)), then \( NZ \) must include the number of matrix sub-elements (i.e., the number of simulation cells in the \( Z \) direction needs to be a multiple of the number of pore systems). The formula for determining the correct value for \( NZ \) is as follows:

\[
NZ = \text{No. of layers} \times 2 + \text{No. of layers} \times (NMATRIX - 1) \quad (6)
\]

In understudy case as an example five-layers have been defined along with 3 matrix subgrids. Thereby, the model would require \( NZ \) of 20.

In the linear case, the distribution of the geometry of the submatrix is increasing following a power law. So, if the pore volume of the submatrix 1 = \( PV1 \) then the distribution of the pore volumes of the remaining submatrix is as follows:

\[
PV1 + aPV1 + a^2PV1 + a^3PV1 + \cdots + a^{NPV1}(Matrix)((\text{where } N = NMARTIX)) \quad (7)
\]

The transmissibility between matrix and fracture cells is calculated by the formula:

\[
DX1 + aDX1 + a^2DX1 + a^3DX1 + \cdots + a^NDX1 = DX \quad (8)
\]

The transmissibility between matrix and fracture cells is calculated by the formula:

\[
TM = CDARYC \times K_{mat} \times V \times \sigma \quad (9)
\]

where \( K_{mat} \) is the permeability of matrix block in \( x \)-direction, \( V \) is the grid cell volume, \( CDARYC \) is Darcy constant value of 0.00112712 (field) and \( \sigma \) is the multiplier, which describes the degree of fracturing of the matrix. This formula was derived by Kazemi [Kazemi et al., (1976), pp.317–326].

2.12 Shale gas flow regime and production mechanism

Shale is characterised by its dual porosity: it contains both primary (micro pores and meso-pores) and secondary (macro pores and natural fractures) porosity systems. The
primary porosity system contains the vast majority of the gas-in-place, while the secondary porosity system provides the conduit for mass transfer to the wellbore. Primary porosity gas storage is dominated by adsorption. Primary porosity is relatively impermeable due to its small pore size. Mass transfer for each gas molecular species is dominated by diffusion that is driven by the concentration gradient. Flow through the secondary porosity system is dominated by Darcy flow that relates flow rate to permeability and pressure gradient.

Figure 4 [right (Sondergeld et al., 2010)] represent different flow regimes and pore types in shale gas reservoirs. The left hand side illustrates the matrix and fracture system showing the desorption of gas, its diffusion in the matrix and Darcy flow through natural fracture system.

When the pressure of natural fracture system in shale drops below the critical desorption pressure, methane starts to desorb from the primary porosity and is released into the secondary porosity system. As a result, the adsorbed gas concentration in the primary porosity system near the natural fractures is reduced. This reduction creates a concentration gradient that results in mass transfer by diffusion through the micro and meso porosity. Adsorbed gas continues to be released as the pressure is reduced.

In shale, gas transport and storage are important for accurate prediction of production rates and for the consideration of subsurface greenhouse gas sequestration. They involve coupled fluid phenomena in porous medium including viscous flow, diffusive transport, and adsorption. Standard approach to describe gas-matrix interactions is deterministic and neglects the effects of local spatial heterogeneities in porosity and material content of the matrix.

The diffusive flow between the matrix and the fracture is given by:

$$ F_i = DIFFMF \cdot D_{c,d} \cdot S_g \cdot RF_i \left( m_i - \rho_{i, g} L_i \right) $$

(10)
where

\( m_i \) \quad molar density in the shale matrix

\( DIFFMF \) \quad matrix fracture diffusivity

\( P_{sh} \) \quad rock density (shale density)

\( D_{c,i} \) \quad diffusion coefficient (shale) component \( i \)

\( RF_i \) \quad readsorption factor component \( i \)

\( S_g \) \quad gas saturation, for desorption a value of unity is used

\( \rho_{sh,L_i} \) \quad equilibrium adsorbed molar density

\( \rho_{sh} \) \quad shale density.

The matrix fracture diffusivity is given by:

\[
DIFFMF = DIFFMFMF \times Vol \times \sigma
\]  

(11)

where

\( DIFFMFMF \) \quad multiplying factor (default = 1.0)

\( Vol \) \quad cell shale volume and \( \sigma \) is the factor to account for the matrix-fracture interface area per unit volume.

Often the sorption times are a quantity that is easier to obtain than the diffusion coefficients. For desorption, the flow is written as:

\[
F_i = \frac{Vol}{\tau_i} \times (m_i - \rho_{c,L_i})
\]  

(12)

where

\[
\tau_i = \frac{1}{D_{c,i} \times DIFFMFMF \times \sigma}
\]  

(13)

is called the sorption time. This parameter controls the time lag before the released gas enters the shale fracture system. The sorption times are given by the diffusion coefficients and the matrix-fracture interface area together with the multiplying factor \( DIFFMFMF \). If the sorption times are known a value of unity can be assigned to \( DIFFMFMF \). The diffusion coefficients can then be assigned to the reciprocal of the sorption times.

2.13 Extended Langmuir isotherm

2.13.1 Langmuir isotherm

The amount of gas contained or adsorbed in the shale at equilibrium conditions can be calculated using the Langmuir isotherm equation. The general Langmuir isotherm equation for gas is the following:

\[
V(P) = \frac{V_L P}{P_L + P}
\]  

(14)
The maximum volume of gas adsorbed at infinite pressure is called Langmuir volume. Langmuir pressure is determined by taking the pressure at about half of the Langmuir volume. Having measured values for gas content, Langmuir volume and Langmuir pressure, then the critical pressure can be calculated as indicated in the following equation. The critical pressure at which Methane starts flowing is proportional to the gas production capability. Higher pressure values are related to larger amount of gas produced.

\[ P_c = \frac{P_l G_C}{V_L - G_C} \]  \hspace{1cm} (15)

The extended Langmuir isotherm is used to describe the shale sorption for the different components. The adsorption capacity is a function of the pressure and the free gas phase composition. For each component, two-parameters need to be input, the Langmuir volume constant and the Langmuir pressure constant. These parameters are typically determined from experiments.

The multicomponent adsorption capacity is calculated by:

\[ L(p, y_1, y_2, \ldots) i = \theta \frac{P_s}{R T_s} \left[ V_i \frac{y_i \frac{P}{P_i}}{1 + \sum_{i=1}^{\infty} \left( y_j \frac{P}{P_j} \right)} \right] \]  \hspace{1cm} (16)

where

- \( \theta \) scaling factor
- \( P_s \) pressure at standard conditions
- \( R \) universal gas constant
- \( T_s \) temperature at standard conditions
- \( V_i \) Langmuir volume constant comp. i
- \( P_i \) Langmuir pressure constant comp. i
- \( y_i \) hydrocarbon mole fraction in gas phase comp. i
- \( p \) pressure.

2.14 Instant and time dependent sorption

Physical sorption is the key process in gas shale systems. Sorptive storage capacity, a principal thermodynamic parameter, is commonly expressed in terms of excess sorption isotherms and depends on pressure, moisture content, temperature, and type and maturity of the organic matter. It can be readily assessed by laboratory experiments at pressures and temperatures relevant for shale gas systems. For both exploration and production purposes, the kinetics of sorption and desorption and the interrelation of sorption and transport processes are of crucial importance.

In shale, the natural fracture systems act as transport avenues while the microporous,
polymer inter-fracture matrix system represents a source or a sink, depending on partial pressure (chemical potential). Rate and efficiency of mass transfer between the fracture and matrix system, and the transport and sorption rates within the shale matrix are therefore of prime interest for quantitative descriptions and modelling.

In instant sorption model (Figure 5), the pore volume has the usual interpretation, and the adsorption-desorption process is represented as a source-sink term into the matrix pore system. It should be noted that the shale volume of each matrix subgrid cell is computed from the average grid cell volume of each shale cell, where the pore volume of all the connected matrix and fracture grid cells are subtracted.

In time dependent method (Figure 6), a simulation cell either contains free gas in a pore space or adsorbed gas in the shale rock. The rock is represented by one simulation cell and the pore volume by a connecting simulation cell. Darcy flow through a rock cell is not permitted. The usual pore volume of a cell now represents the rock volume where the imaginary micro pore space flow is accounted for by a diffusive flow equation. For a cell having a non-zero shale region number, a porosity value should be specified that corresponds to a rock fraction value. For cells having a zero shale region number, the porosity value corresponds to the pore volume fraction.

Figure 5  Instant sorption-conceptual model (see online version for colours)

Figure 6  Time dependent sorption-conceptual model (see online version for colours)

2.15 Enhanced shale gas recovery and CO₂ sequestration

Other than primary recovery, more effective recovery methods, such as enhanced shale gas recovery by gas injection are under feasibility study. Nitrogen, carbon dioxide or the mixture of two-gases (such as flue gas), are the cases that can be considered for injection. These gases are chosen for different reasons and different mechanisms are employed in
enhancing shale gas recovery.

Nitrogen is used because of its availability in the air and because it is more or less a non-reactive gas. Nitrogen injection enhances shale gas recovery by lowering the partial pressure of methane in the free gas phase in the pore spaces to cause desorption. Carbon dioxide is used because it is a greenhouse gas. Injecting CO$_2$ from an anthropogenic source reduces atmospheric emissions of greenhouse gas.

CO$_2$ which is more strongly absorbable than methane is injected into the shale natural fracture system during the recovery process; it is preferentially adsorbed into the primary porosity system. Upon adsorption the CO$_2$ drives the CH$_4$ from the primary porosity into the secondary porosity system. The secondary porosity pressure is increased due to CO$_2$ injection and the CH$_4$ flows to the production wells (Shi and Durucan, 2003). The CH$_4$ is thereafter, produced and CO$_2$ is retained in the shale beds.

Injecting CO$_2$ into shale gas reservoirs achieves not only enhanced shale gas recovery, but also greenhouse sequestration underground. Therefore, shale gas reservoirs are likely to play a role in sequestration similar in magnitude to coals in near future (Nuttall, 2005).

There is no field operation for gas injection in shale reservoirs up to date and there is no numerical modelling and simulation study as well (Seto et al., 2006).

The pore volume and transmissibility in the fractures are affected by compression of the shale and swelling/shrinkage of the shale matrix due to adsorption/desorption. Pore volume multiplier is given in the form of:

$$V_m = 1 + C_O (P - P_o) + C_e (e - e_o)$$  \(17\)

Permeability change is assumed to follow:

$$\frac{k}{k_0} = \left(\frac{\phi}{\phi_0}\right)^3$$  \(18\)

The strain due to swelling can be estimated from the adsorbed contents through a Langmuir like expression. Sorption pressure is imposed avoiding swelling for undersaturated situations.

$$e = e_a \frac{P_{sorb} b}{1 + P_{sorb} b}$$  \(19\)

And the extension of above formula to multi-component system is:

$$e_k = e_a k \frac{P_{sorb} b_k a_k}{1 + P_{sorb} \sum j \left[b_j a_j\right]}$$  \(20\)

3 Methodology

For this study, an integrated workflow which demonstrates a quantitative platform for shale gas production optimisation through capturing the essential characteristics of shale gas reservoirs has been proposed (Figure 7).

Development of unconventional resources requires the collection and analysis of
large volumes of data – a sizable investment. Our approach uses this integrated information to the fullest, delivering different scenarios to enable the best business decisions. Better reservoir knowledge and increasingly sensitive technologies are making the production of shale gas economically viable and more efficient.

Figure 7 An integrated for shale reservoir modelling and simulation (see online version for colours)

4 Results and discussion

4.1 Natural fracture modelling and upscaling

A DFN using typical shale properties was generated stochastically based on 80 acre spacing. Two-fracture sets have been defined based on the available data. Figure 8 and Figure 9 (left) illustrate the fracture sets, aperture, and length. The complex DFNs were up-scaled using both Oda and flow-based methods in order to simulate fluid flow through the system. Figure 9 and Figure 10 show the fracture porosity, permeability and matrix-fracture coupling factor (SIGMAV).

Table 1 Natural fracture network properties

<table>
<thead>
<tr>
<th>Distribution Fracture set</th>
<th>Fracture area/vol.</th>
<th>Geometry Sides Elongation ratio</th>
<th>Geometry Length Shape Scale</th>
<th>Orientation Mean dip</th>
<th>Mean dip Azimuth</th>
<th>Concentration</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.1</td>
<td>4</td>
<td>2</td>
<td>Power</td>
<td>2.1</td>
<td>50</td>
</tr>
<tr>
<td>2</td>
<td>0.05</td>
<td>4</td>
<td>2</td>
<td>Power</td>
<td>2.1</td>
<td>50</td>
</tr>
</tbody>
</table>

80 15 40
84 345 70
The fracture network characteristics used for the base model are shown in Table 1. Fracture aperture was less than 10 micrometer or even less than 5 micrometer based on core analysis.

Figure 8  DFN model-fracture sets and aperture (left to right) (see online version for colours)

Figure 9  DFN model-fracture length and on the left up-scaled property sigma (left to right) (see online version for colours)

Figure 10  Up-scaled properties-fracture permeability in i-direction and fracture porosity (left to right) (see online version for colours)
4.2 Hydraulic fracture design and modelling

The modelled shale gas production well reaches a total depth of 2370 ft (driller’s depth) and has been completed with 4” production casing. The well was perforated and hydraulically fractured in eight-stages.

Figure 11 shows the logarithmic local grid refinement around the eight-stages of hydraulic fractures of understudy shale gas well with associated global grids. The finest grid, which represents hydraulic fracture, has a permeability of 30 md and the rest of grid blocks have a fracture permeability value of 0.0004 md.

Figure 12 illustrates a more detailed picture of hydraulic fracture and corresponding LGRs without global grids. As can be seen the finest grid, which is identified by red color, represents the hydraulic fracture.

Figure 11 Hydraulic fractures and logarithmic local grid refinement around them with global grid (see online version for colours)

Figure 12 Hydraulic fractures and logarithmic local grid refinement around them without global grid (see online version for colours)

4.2.1 The well/field data

Some basic well/reservoir data are listed as following:

- gas composition: 85.1, 3.12, 0.25, 0.1, 0.2, 11.23 for (mol %) for C1, C2, C3, C4-6, CO2, and N2, respectively
reservoir temperature: 85 (deg F)
initial reservoir pressure: 780 psi
number of grid cells: 139*42*5 (Corner point gridding method)
grid size: 50*50 ft
net pay thickness: 100 ft.

Because this well had no indication of water production, fracture and matrix have been assumed to be fully saturated with gas. The production rates along with known reservoir features have been imported to the model. Initial values for the adjusting parameters are chosen and the compositional simulation (dual porosity model) is run. The output from the simulation is compared with the matching target. If the match is not satisfying, the adjusting parameters will be modified and the process will be repeated until a satisfactory match is achieved. The matching objective was monthly production rate.

The history matching in conjunction with reservoir characterisation and fracture properties (both natural and hydraulic), help to improve the understanding of the reservoir and establish a sensible initial condition of the under-study shale gas reservoir for the simulation of the CO₂ injection process.

The history matching process has been performed. Figure 13 shows the history matched production rate of understudy well. In this figure, red circles represent the actual production rates while the blue dash line stands for the history matched production rate (simulation result).

The history matched parameters are as follows:

- matrix porosity: 5%
- matrix permeability: 4E-5md
- natural fracture porosity: 0.5%
- natural fracture permeability: 4e-4md
- matrix – fracture transfer function(sigma) = 0.095
- number of hydraulic fracture stages = 8
- hydraulic fracture conductivity = 60md-ft
- hydraulic fracture spacing = 400 ft
- hydraulic fracture length = 500 ft
- hydraulic fracture height = 90 ft
- langmuir pressure: 1,322 psi
- langmuir volume: 0.164 mscf/ton
- diffusion time: 6 days
- rock compressibility = 1.57E-4
- non-darcy flow coefficient t = 5
- matrix subdivision = 1
• gas saturation = 100%
• number of shale regions = 1.

**Figure 13** Production history matching result (see online version for colours)

The history-matched model has been run for 15-years. Following figures show the top view of matrix pressure distribution in reservoir for the first three-month, five, ten and 15-years of production.

**Figure 14** Shale matrix pressure distribution in the reservoir and around the hydraulic fractures for first three and 12-month of production (see online version for colours)

**Figure 15** Shale matrix pressure distribution in the reservoir for first 60 and 120 month of production (see online version for colours)
4.3 Comprehensive uncertainty analysis

Uncertainty analysis is a quantitative method of determining the effect of parameter variation on model results. The purpose of uncertainty analysis is to quantify the uncertainty in the calibrated model caused by uncertainty in the estimation of fracture and shale matrix properties. It is a tool to identify the model inputs that have the most influence on model calibration and predictions. It provides an idea about the key parameters that should be adjusted during model calibration.

If a small change in the input parameter or boundary condition causes a significant change in the output, the model is sensitive to that parameter or boundary condition.

Figure 17 shows the result of uncertainty study on matrix porosity with different values of 1, 5 and 8% and also the matrix pressure distribution in the reservoir and around the hydraulic fractures. By decreasing the matrix porosity, the amount of reserve will be decreased and as a result, the reservoir will be depleted faster. Therefore, the
matrix pressure drop will happen much faster.

**Figure 18** Uncertainty analysis on matrix permeability (md) and corresponding matrix pressure distribution (see online version for colours)

- Figure 18 shows the result of uncertainty study on matrix permeability with different values of 4E-3, 4E-5 and 4E-6 md and also the matrix pressure distribution in the reservoir and around the hydraulic fractures. The change of matrix permeability does not have significant impact on cumulative production.

**Figure 19** Uncertainty analysis on fracture-matrix transfer function (Sigma) and corresponding matrix pressure distribution (see online version for colours)

- Figure 19 illustrates the effect of changing the matrix-fracture transfer function on productivity of shale gas well. A higher value of sigma shows a better connection of fracture and matrix in dual porosity model and as a result faster depletion of the reservoir with higher cumulative production.
As shown in Figure 20 natural fracture porosity does not play an important role on productivity of shale plays. Despite fracture porosity, fracture permeability effect on well productivity is substantial.

Figure 21 shows how sensitive shale gas production is to natural fracture permeability variation in the reservoir. Any increase of fracture permeability will noticeably increase the production and cause larger pressure drop in the reservoir.
Even though in many shale plays, these natural fracture conduits are filled with calcite, a successful hydraulic fracturing job can open these fractures and create complex fracture networks.

Figure 22 through Figure 24 show the effect of hydraulic fracture properties including fracture conductivity, length and height on shale gas production.

Figure 25 illustrates the consequence of less hydraulic fracture spacing and number of stages on shale gas reservoir depletion and production.
Systematic approach to numerical simulation

Figure 24 Uncertainty analysis on hydraulic fracture height (ft) and corresponding matrix pressure distribution (see online version for colours)

Figure 25 Uncertainty analysis on hydraulic fracture spacing (ft) and corresponding matrix pressure distribution (see online version for colours)

Figure 26 uncertainty analysis on shale gas content (Mscf/ton) and corresponding matrix pressure distribution. Shale gas content is also important factor on productivity of shale plays. A prolific shale gas reservoir obviously should have high gas content in matrix. Figure 26 shows the result of uncertainty analysis on gas content of 0.164, 0.06 and 0.02 MSCF/ton on cumulative production.

In order to model shale gas sorption, instant sorption and time dependent sorption models have been used and compared. According to the uncertainty study as shown in Figure 27, using the instant sorption model will significantly increase total gas production of shale gas well. In this model, it has been assumed that there is no diffusion in matrix and gas will be transferred to the matrix instantly. Therefore, this model may overestimate shale gas production and it should be used with much more caution.
Matrix discretisation model is used to capture long transient flow through the shale matrix. As illustrated in Figure 28 the transient flow facilitated by matrix subdivision has a significant impact on early gas production and is a key factor during history matching process.

As illustrated in Figure 29, which represents the comparison of the influence of most of shale properties on flow rate based on the uncertainty analysis results, the key parameters that have substantial effect on production behaviour are natural fracture permeability, sigma and hydraulic fracture parameters including fracture spacing, height, half-length and conductivity. Therefore, a successful hydraulic fracture design and modelling is a critical factor on unlocking most of shale plays.
4.4 CO$_2$ injection impact on shale gas productivity and sequestration

As explained before, although adsorbed gas may comprise more than 40% of initial shale gas in place, the ability to produce the adsorbed gas is limited due to nano-Darcy shale matrix permeability, high FBHP and desorption profile, which requires relatively low pressure to produce significant amount of adsorbed gas. Therefore, desorbed gas
production is probably a minor component in economic development of many shale gas plays and can possibly be ignored in many reservoir simulations, especially when evaluating initial well performance (first five-years) (Cipolla et al., 2009a, 2009b, 2009c).

CO₂ injection due to higher affinity of shale matrix to capture CO₂ and release methane might be helpful in increasing shale gas productivity and sequestrating the CO₂.

The history-matched model has been used for CO₂ injection purpose and due to long simulation run; the study has been focused on the smaller part of reservoir (around 30 acre). As shown in Figure 30, the well produced methane for five-years, the production was stopped after that and CO₂ injection was stared and continued for five-years (due to low injectivity), injection was stopped and the well was put on production for the next 20-years.

**Figure 30** Gas production rate and cumulative-CO₂ injection case (see online version for colours)

Because of special characteristics of shale gas reservoirs, low injectivity of CO₂ is expected. But the key issue is to monitor the behaviour of shale matrix in contact with injected CO₂. After 20-years of production following the injection period, there is no CO₂ observed in produced gas meaning that all the CO₂ has been captured by shale matrix.

Figure 31 illustrates the pressure distribution changes during the primary production (October 2008 to October 2013) and injection start up at November 2013, while the producer was shut in. October 2018 was the last month of injection and after that on November 2018 injection was stopped and the producer was opened to flow until October 2038.
Figure 31  Matrix pressure distribution around the producer and injector (see online version for colours)

Figure 32  Molar density of methane in matrix before and after CO$_2$ injection (see online version for colours)
It is clearly shown that injection has increased the reservoir pressure. This is in contradiction with the scope of creating enough pressure drop in order to expedite methane desorption from shale matrix. Nevertheless, the simulation results show that all the injected CO$_2$ has been absorbed by shale matrix and consequently, methane has been released to the fractures and as a result it has been sequestered successfully. Therefore, shale gas reservoirs are good candidate for sequestering CO$_2$ in near future.

Figure 32 shows the molar density distribution of methane in shale matrix before injection begins in October 2013, first month of injection on November 2013 and after 20-years of production (October 2038).

5 Conclusions

In this paper, an integrated workflow, which demonstrates a quantitative platform for shale gas production optimisation through capturing the essential characteristics of shale gas reservoirs, has been proposed.

Comprehensive uncertainty study has been performed on all parameters, which play role in production from shale gas reservoirs. The results of this study showed that the fracture properties (both natural and hydraulic) could have a profound effect on the productivity of shale reservoirs.

In order to accurately model non-Darcy flow in hydraulic fractures, LGR grids have been used. Compositional simulator is used along with dual porosity model to simulate flow in shale gas reservoir. Matrix discretisation technique was examined successfully to capture transient behaviour of flow in shale.

Optimising the multistage hydraulic fracture treatment design guarantee the successful production from most of shale plays.

Because organic material has a greater sorption affinity for CO$_2$ rather than methane, a feasibility study has been performed to evaluate the applicability and significance of CO$_2$ injection on expedition of desorption process and also CO$_2$ sequestration in shale. Our study shows that almost all the injected CO$_2$ is sequestered in shale matrix and methane has been replaced by CO$_2$.

Single well history matching has been performed and the fracture and reservoir properties are varied within a range that appears consistent with actual under-study shale gas reservoir performance.

It is highly recommended to examine the capability of simulators by performing shale gas modelling in complex structure and performing multiple wells history matching.

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References


