1 Introduction

1.1 Motivations and objectives

Energy is one of the most critical factors for the economic development. Due to the world's increasing energy consumption and the climate change, the strategic energy storage draws a lot of attention (Kolditz et al. 2015). Tight gas has become one of the most important fields in unconventional natural gas exploration and development. Large-scale development and utilization of tight gas in the United States not only boosted the rapid recovery of US natural gas production, but also promoted the progress of tight gas exploration and development in many countries (Figure 1.1). The application of horizontal drilling and hydraulic fracturing technologies made it possible to develop the U.S. tight and shale gas resource, contributing to nearly doubling of the estimates for the total U.S. technically recoverable natural gas resources over the past decade. Tight gas, shale gas, and coalbed methane resources in Canada and China account for about 80% of total production in 2040 in those countries.

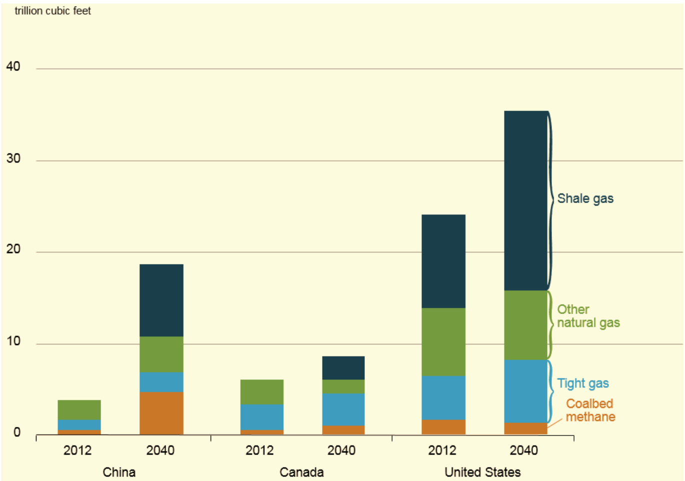

Figure 1.1 Natural gas productions by type in the United States, China and Canada, 2012 and 2040 (EIA 2016)

Tight gas reservoir is known as "tight" because it has a low permeability (less than 0.1 md) and is usually composed of so-called hard rocks like sandstone. Tight gas reservoirs require stimulation because the permeability of the formation is simply not high enough for the well to produce natural gas, of course, taking the economic aspects into account. To increase the wellbore/reservoir connection by means of a high contact area and to enhance the well permeability capacity (net thickness × permeability) to a technically possible maximum hydraulic fracture height (h_f), hydraulic fracturing (Figure 1.2) is referred to as a suitable reservoir stimulation technique on tight gas reservoirs. Especially under difficult conditions and limited reservoir connection, more obvious on completed horizontal wells, multiple hydraulic fracture treatments were performed to develop an economic well productivity and to access sufficient dynamic gas-in place volumes.

For the hydraulic fracturing treatment design many parameters should be taken into consideration. The main design parameters are treatment schedule (e.g. injection rate/volume/ time, proppant concentration, total injected proppant mass and proppant injection time), fluid properties (e.g. type, density, viscosity and additives), proppant properties (e.g. type, density, diameter, strength and hydraulic conductivity under closure stress) etc. These parameters are determined by geological conditions, rock mechanical and hydraulic properties, temperature, in-situ stress state, reservoir pressure, stress and conductivity requirements etc. Actually, the optimal number and spacing of fracture treatments are based on the reservoir permeability, the length of the well section within the potential layer (distance between the two border fractures), net thickness, fracture half-length, fracture conductivity, the expected compartments (estimated by means of LWD interpretations: sub-seismic faults and/or facies changes), vertical to horizontal permeability anisotropy ((k_v/k_h)-ratio) and the drainage radius (or assumed reservoir borders) (Koehler & Kerekes 2006a). The optimization can be achieved through numerical simulation.

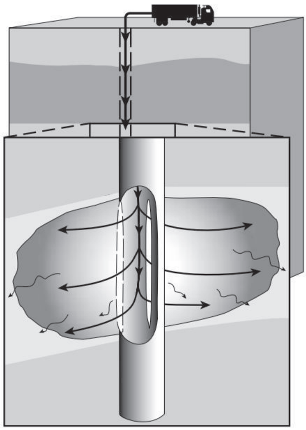

Figure 1.2 Cross-sectional views of the hydraulic fracturing (Economides & Nolte, 2000)

Modern experimental equipment, fast development of computer techniques and the simulation methods make the study of coupled THMC processes possible. Different numerical codes have been developed in recent years, which are able to consider all the process together, such as OpenGeoSys (Kolditz et al. 2012), DuMu^x (Flemisch et al. 2011), COMSOL Multiphysics (COMSOL 2012) etc. Based on the experimental results and analysis a bank of benchmarks of coupled THMC processes have been set up (Kolditz et al. 2016). Hydraulic fracturing involves many physical processes such as stress change and deformation of rock formation induced by pore pressure change in fractures and pores, fluid flow within fracture and formation including their interactions, fracture propagation, proppant transport and settling inside the fracture. These processes are very complicated, and the mathematical modeling of these Multiphysics processes is a challenging task. From 1950s the first theoretical models of hydraulic fracturing were created and then gradually developed, e.g. KGD (plane strain) (Khristianovic & Zheltov 1955, Geertsma & Klerk 1969) and PKN 2D models (Perkins & Kern 1961, Nordgren 1972), lumped and cell based pseudo 3D models as well as planar 3D model. They were solved by analytical, semi-analytical or fully numerical methods respectively (Adachia et al. 2007, Economides & Nolte 2000, Siebrits & Peirce 2002). However, due to the complexity of the involved coupled processes as well as the challenges from mathematical modeling of this Multiphysics process, much work is still to be done in the future.

In the petroleum industry there are many standard tools for the design of hydraulic fractures and prediction of gas productions. E.g. reservoir model generation, hydraulic fracturing simulation and gas production simulation are usually carried out using Petrel, FracPro, MFrac as well as ECLIPSE separately. Petrel is a product of Schlumberger, which used to build 3D geological models of petroleum reservoirs (Schlumberger 2014). MFrac used semi-analytic methods and formulated between a pseudo-3D and full 3-D type model with an applicable half-length to half-height aspect ratio greater than about 1/3 (Meyer 1989). MFrac accounts for the coupled parameters affecting fracture propagation and proppant transport (Meyer 2012). However, MFrac does not consider the hydro-mechanical conditions under contact condition after fracture closure. The simulation is forced to stop when the proppant reaches its maximum value of the compacting factor, even when the most upper part of the fracture area is still open without proppant (full closure is not yet reached). That means, the area of the proppant placement is underestimated. In fact, the fluid pressure within the fracture under contact could be smaller than the normal stress perpendicular to the fracture wall. Therefore, it is difficult to simulate the compact proppant at the upper part of the fracture during the closure process. The simulated fracture geometry is too ideal. ECLIPSE is also a product of Schlumberger, which is used to simulate the production of black oil, compositional, thermal, and streamline reservoir. Unfortunately, ECLIPSE can only be used in the reservoir simulation. It is not capable for geomechanical simulation. In ECLIPSE the fracture can only be considered through an equivalent continuum approach and the fracture properties are independent on the stress conditions. So far, there are no numerical tools in the petroleum industry which can optimize the whole process from geological modeling, hydraulic fracturing until production simulation with the same 3D model with consideration of the thermo-hydro-mechanical coupling. There are always conversion and adaption of the results from different stages with different softwares. The optimization of a single fracture during the stimulation phase does not represent the performance of the whole horizontal well. In the petroleum industry, the fractures are normally designed one after another. 3D production simulation will not be performed during this phase. However, the fractures will influence each other during the production. Therefore, optimization design should also be considered from the perspective of production, especially for multiple hydraulic fractures. The simulation of the production phase with the created fractures in one model is very important for the optimization design.

In this dissertation, the complete modeling from multiple hydraulic fractures initiation to production with the same full 3D simulation model, as well as smoothly integration of the simulated multiple fracture geometries and conductivities into production simulation was performed. It was realized based on the hydraulic fracturing model developed by Zhou and Hou (2013), Zhou et al. (2014), Li et al. (2016) and Feng et al. (2016).

The objective of this thesis therefore is the optimization study of tight gas production by using multistage hydraulic fracturing technology based on numerical simulations and the measured data from the tight gas reservoir Leer in the North German Basin.

1.2 Thesis outline

In the framework of this thesis the concept and tools were developed for the optimization study of tight gas production by using multistage hydraulic fracturing technology.

The fundamental of the whole concept was the numerical model for the hydraulic fracturing and the associated reservoir simulation model for the gas production. Such concept was realized by coupling of the previously developed 3D hydraulic fracturing model in FLAC3D^{plus}, the multiphase multicomponent flow model in TOUGH2MP, as well as the software optiSLang for sensitivity analysis and robust design optimization. With these tools, 3D simulation model can be generated according to the measured geological and geophysical data of the tight gas field and verified against the measured treatment and production data. Based on the verified models, numerical simulations with varied parameters can be carried out for the optimization of tight gas production regarding the whole process from the beginning of the stimulation until the end of the production.

Figure 1.3 describes the whole concept and flow chart of this thesis. Firstly, the Frac-Simulator FLAC3D^{plus}-optiSLang was developed for the history matching of multi-stage hydraulic fracturing phase. Then the FracProdu-Simulator FLAC3D^{plus}-TMVOCMP-optiSLang was developed for the history matching of the gas production phase. Both tools were verified by numerical simulation examples. As the case study the natural gas field Leer located in the North German Basin was selected. A full 3D hydraulic fracturing model was generated based on the geological and geophysical data of this gas field. For the stimulation phase, the bottomhole pressure (BHP) development derived from the measured treating pressure (WHP) was set as the goal of history matching. After the history matching a corresponding full 3D reservoir simulation model was generated based on the data from the gas field, including the created hydraulic fractures with their own geometry and proppant distribution obtained during the hydraulic fracturing simulation. For the history matching of the production phase, the bottomhole pressure (BHP) development derived from measured well head pressure (WHP) was used as input data for the stress sensitive reservoir simulation. The gas production rate was set as the goal of history matching. To maximize the productivity of the tight gas wellbore, numerical simulations were carried out with different design parameters, including proppant type (density, diameter as well as stress-dependent conductivity), viscosity of the injection fluid and injection time to obtain their sensitivities. At the last stage, the treatment schedule and fracture spacing were varied based on the history matched model. Various numerical simulations of hydraulic fracturing and subsequent reservoir simulations were carried out for the optimization goal. A new dimensionless fracture conductivity was proposed to better evaluate the hydraulic fracturing treatment results.

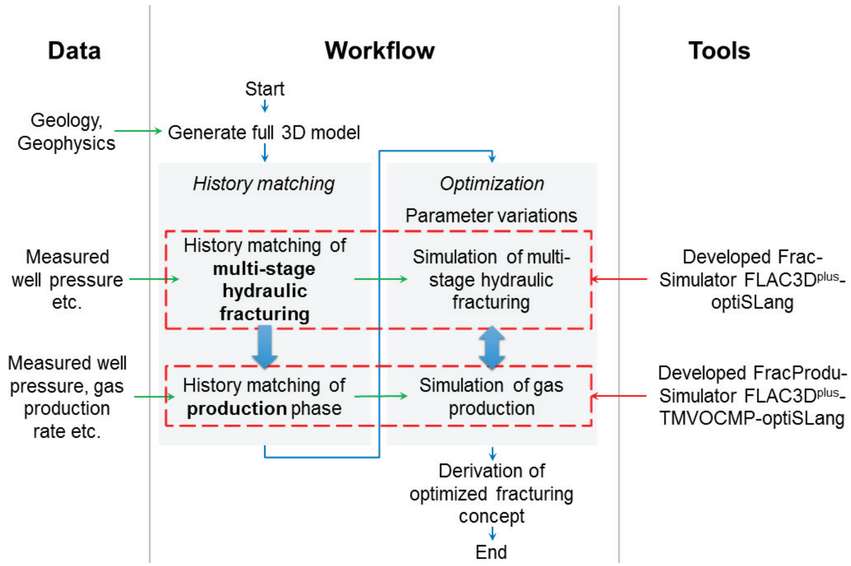

Figure 1.3 Flow chart of this thesis

The following contents are integrated in this thesis.

In Chapter 2, the research location, geological conditions are introduced. The development history, including the drilling of horizontal wells and hydraulic fracturing are reviewed.

Chapter 3 introduces the fundamentals of hydraulic fracturing and application in Leer, such as fracturing fluids, well types and fracture orientation, procedure and stages of hydraulic fracturing, bottomhole pressure record, formation characterization (from well test and well logging) and fracture conductivity lab testing.

In Chapter 4, the historical development of hydraulic fracturing modeling is introduced, e.g. penny-shaped fractures, 2D, planar 3D and pseudo-3D. A real 3D model with FLAC3D^{plus} is used as the basic simulator for the numerical simulation in this dissertation.

In Chapter 5, the developed Frac- and FracProdu-Simulators optiSLang-FLAC3D^{plus} and optiSLang-FLAC3D^{plus}-TMVOCMP for the optimization of multistage hydraulic fracturing treatment were introduced. After the basic introduction, verifications of the simulators were performed.

In Chapter 6, numerical simulations with the developed simulators were performed for the history matching of the stimulation and production phase. By analyzing and comparing the simulation results, a new calculation formula of dimensionless fracture conductivity F_{CD} was proposed for better prediction of the subsequent production phase, which is recommended to use in fracturing treatment design. Based on the history matched stimulation model and production model, sensitivity analysis with consideration of proppant type, viscosity of the injection fluid and injection time/rate, variations of the treatment schedule and fracture number/spacing, were performed to optimize the tight gas production. Then the optimized parameter design was applied for the production in a tight gas reservoir in the North German Basin.

The innovation of this study lies in the following points. On one hand the complete modeling from multiple fractures initiation to production with the same 3D simulation model, as well as the smoothly integration of the simulated multiple fractures geometry and conductivities into production simulation was realized. On the other hand, a new calculation formula of dimensionless fracture conductivity F_{CD} was proposed for a better fracture treatment design.

2 Tight gas field Leer in the North German Basin

2.1 North German Basin

The North German Basin (Figure 2.1) is a passive-active rift basin located in central and west Europe, lying within the southeastern most portions of the North Sea and the southwestern Baltic Sea and across terrestrial portions of northern Germany, Netherlands, and Poland (Hubscher et al. 2010). The North German Basin is a sub-basin of the Southern Permian Basin that accounts for a composite of intra-continental basins composed of Permian to Cenozoic sediments, which have accumulated to thicknesses around 10–12 kilometers (Scheck & Bayer 1999, Gemmer et al. 2003).

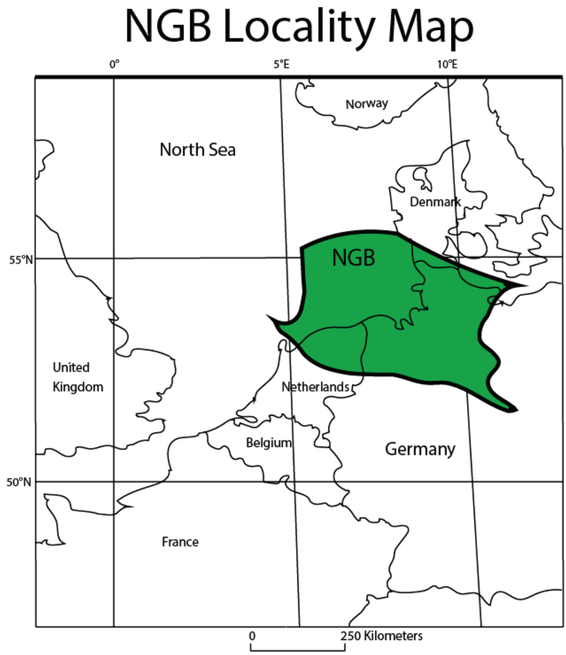

Figure 2.1 The North German Basin located in Western Europe, represented as the green region defined by USGS

The evolution of the North German Basin experienced the following phases: Initial rifting, main phase of subsidence, secondary rifting, doming, tertiary rifting, inversion and final subsidence. The initiation of the Northern German Basin took place in the Late Carboniferous approximately 295-285 Ma (million years ago) in association collapse of the Variscan Orogeny due to wrenching tectonics in the over-thickened crust in the northern foreland of the Variscan Orogeny (Ziegler 1993, Brink 2005, Van Wees 2000). The last phase of subsidence occurred during the Cenozoic.

The stratigraphy sequence of sediments recorded the depositional history of the North German Basin, which make up the basin. The sedimentary basin was assembled above the Lower Paleozoic crystalline basement formed during the Caledonian Orogeny about 420-400 Ma (Sajjad, 2013).

Figure 2.2 breaks down the stratigraphic units of the North German Basin through time. The lowermost stratigraphic unit of the North German Basin is the lower Rotliegend group, which is from Permian of the Paleozoic era and composed primarily ignimbrites, rhyolites, and andesites, while also having minor amounts basalts (George 1993). Rotliegend is also the target formation of the tight gas field Leer, which was studied in this thesis.