INTEGRATED RESERVOIR CHARACTERIZATION AND MODELING IN SUPPORT OF ENHANCED OIL RECOVERY FOR BAKKEN

by

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ABSTRACT

This research presents an integrated reservoir characterization study of the Bakken fields in North Dakota. First, the Bakken petroleum geology is studied to evaluate the flow-related properties of the hydrocarbon-bearing formations from core scale to field scale. This part of the research focuses on the Middle Bakken formation which has been the target for horizontal drilling in Williston Basin.

Second, the fluid flow hierarchy in the Middle Bakken formation is determined by comparing the differences between permeability measured from laboratory core experiments and field tests. Effective permeability measurements from well tests infer the reservoir contains both micro and macro fractures. Core permeability measurement alone does not provide the fluid flow characterization. In addition, laboratory flow experiments to determine basic core properties such as porosity, permeability, wettability, pore size, mineralogy, and fluid saturations and specific laboratory tests with low salinity brine and CO₂ are conducted.

Third, geological and petrophysical properties are integrated into a compositional dual-porosity reservoir model to simulate production performance. Time analysis of flow and pressure over the history of a well, supplemented by the pressure and rate transient analysis of shorter-duration well tests, provides the most important flow characterization data for reservoir modeling. The reservoir model has a flow hierarchy focusing on the stimulated reservoir region with the nanometer-scale matrix pores connected to a network of interconnected micro-fractures and macro-fractures and eventually connecting to the wellbore via hydraulic fractures. Reservoir heterogeneity is addressed using a heterogeneous matrix and fracture petrophysical model which combines the core analyses and well log data. The integrated modeling approach is used for planning of production options and evaluating enhanced oil recovery strategies.

Finally, the technical feasibility of producing more oil from Bakken reservoir by waterflooding and CO₂ injection is investigated. Several simulation scenarios are presented to provide insight about the injected fluid, injection scheme, well pattern, injector well completion, and well spacing.

In summary it is concluded that: (1) the difference in the magnitude of core-measured permeability ($10^{-3}$-$10^{-5}$ md) and field-measured permeability ($10^{-1}$-$10^{-2}$ md) and the presence of a micro-fracture network in Bakken are the main reasons for facilitating oil production from Bakken. Furthermore, for enhanced oil production, the micro-fracture network is the main pathway for delivering water or CO₂ to the tight matrix of the Bakken formation. (2) Dual-porosity modeling is the prudent approach for simulating primary production and improved oil recovery from Bakken because of the flow hierarchy; that is, flow from matrix to microfracture and microfracture network, then to the multi-stage hydraulic fractures, and eventually to the horizontal wellbore. (3) CO₂ injection, via injector-producer well pattern,
can enhance oil production but, for economic viability, recycling of the produced CO₂ is absolutely necessary. (4) Oil production by CO₂ injection is higher than by waterflooding, but field pilot tests are needed before any major field project is implemented.
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CHAPTER 1
INTRODUCTION

This thesis documents the details of an enhanced oil recovery (EOR) research project conducted at the Marathon Center of Excellence for Reservoir Studies and at Marathon Oil Corporation (MOC) facilities. The project scope includes examining the production characteristics of a Bakken reservoir, design of appropriate laboratory experiments for EOR, and reservoir simulation to forecast field performance. To accomplish the goals, we studied and analyzed core properties, well logs, reservoir geology, pressure and rate transient tests, well performance indices, and laboratory flow experiments.

1.1 Objectives

The objective of this research is to explore technical feasibility of producing more oil from Bakken reservoirs by an innovative enhanced oil recovery technique. This requires a greater understanding of reservoir characterization including rock and fluid properties in conjunction with well performances. Currently oil production from Bakken is by depletion drive only, which recovers about eight to twelve percent of oil in place. Such low primary recovery in a very high oil volume remaining in place is a strong motivation to investigate the application of improved and enhanced oil recovery methods in Bakken because small improvements in productivity and recovery factor could lead to millions of barrels of additional oil. None of the conventional improved and enhanced oil recovery techniques have shown promise so far. Any successful innovation will rely on a scheme or technology that would mobilize a portion of the oil trapped within the low permeability matrix in Bakken, which is pursued in this thesis.

1.2 Background

Improved drilling, hydraulic fracturing, innovative completion methods, and presence of natural fractures have contributed to economic oil and gas production from liquid rich shale reservoirs. The oil from Bakken is typically high quality light oil. Because of its low viscosity, high reservoir pressure, and large solution gas-oil ratio, oil can be flowed rather nicely in the complex nano-pores of the matrix and surrounding fractures. Specifically, the Bakken reservoirs are elastic sediments with a complex pore structure, which is hard to quantify using conventional techniques. New fracturing technology has been aimed at improving the conductivity of the natural fracture networks so that trapped oil in the matrix can be drained more efficiently.

Much research has been conducted in the last ten years to understand the flow mechanisms in unconventional shale reservoirs. In fact, two decades ago, these reservoirs were considered uneconomic to
produce due to very low production rates. Today, through advanced well completion and stimulation techniques, production from shale reservoirs has been continuously increased. However, we still do not know the exact mechanisms of fluid flow and mass transfer in shale.

The following characteristics are attributed to production of natural gas and light hydrocarbon liquids from shale formations: 1) low viscosity of hydrocarbon fluids—both gas and light oils, 2) high compressibility of fluids, 3) dominance of very low molecular weight components in the hydrocarbon fluids, 4) abnormally high initial reservoir pressure which might have caused intrinsic microfractures, 5) enhancement of natural micro and macro fractures as a consequence of the multi-stage hydraulic fracturing, and (6) favorable phase envelop shift of hydrocarbon mixture and favorable ratio of gas-oil split in nanopores. In Bakken, depletion drive assisted by low oil viscosity and high solution gas-oil ratio, seems to be responsible for oil production.

1.3 Problem Statements

Reservoir Characterization: Abnormally high pressure, high temperature, low permeability, and low porosity are common characteristics for most of shale plays. And, the reservoir ultimate recovery potential from these reservoirs depends on lithology, mineralogy, thermal maturity, fluid properties, and pore types. Specifically, in shale oil reservoirs, existence of relatively larger inter- and intra-granular pores and pore throats and fracture porosity provides sufficient ease of mobility to oil to generate economic well flow rates. To understand the role of these complex parameters requires a dedicated reservoir characterization approach i.e., from core scale to a field.

Rock Properties: Field observations and performance results to date have suggested that, to various degrees, all unconventional are dual-porosity fractured reservoirs where matrix storage feeds micro-fractures, macro-fractures, a set of propped hydraulic fractures emanated from a horizontal wellbore, and eventually the well. Understanding matrix and fracture system and their contribution to overall production is the key in identifying reservoir drivers affecting well productivity during a well’s life. However, quantifying the matrix-fracture flow map and deliverability is challenging because of low permeability and low porosity of unconventional reservoirs. The stress-dependent porosity and permeability of shale strongly affect production behavior. Measuring these properties in laboratory, using conventional reservoir techniques, is difficult and time consuming, therefore, new approaches are needed.

Fluid Properties: There have been many studies in the literature on the pore-dependence of fluid properties in unconventional reservoirs, though the corresponding physical phenomena are still hypothesis. Besides the nano-size pore structure, the fracture network, long-term matrix contribution, and the high average pore pressure in the reservoir are also considered to impact the well fluid production.
characteristics and the delivery potential. The effect of reservoir fluid compositions on primary recovery needs further investigation to effectively evaluate appropriate IOR/EOR applications.

Formation Testing: Accurate determination of reservoir deliverability is fundamental for the economic development of any field. In unconventional reservoirs, there is a need for reliable pressure transient tests to provide the effective formation permeability of the fracture-matrix for deliverability calculations. This effective permeability can then be compared to laboratory measured core permeability of the matrix rock samples. This comparison is the basis for planning early production options and subsequent enhanced oil recovery decisions.

Well Flow Regime: In unconventional reservoirs, we observe a long transient flow regime due to the nano-permeability of the matrix. This characteristic affects the reliability of the ultimate hydrocarbon recovery estimates because the true reservoir boundary cannot be felt in a reasonable length of time. The technological advancements in completion and stimulation further complicate the well recovery estimations. Commonly used empirical rate-time techniques to estimate ultimate recovery has a high uncertainty considering the short-term multi-stage horizontal well history. More integrated and comprehensive approach is required to analyze well production decline characteristics utilizing the empirical approaches as well as the analytical and numerical modeling.

Modeling: Several different conceptual modeling approaches have been used to simulate oil and gas flow in low permeability shale reservoirs. While some of these approaches have yielded the same ultimate recoveries during depletion, the models which accurately simulate the flow pathways are more reliable for improved oil recovery (IOR) or enhanced oil recovery (EOR) evaluation and forecasting. This includes fine-tuning the decline curve analysis. Specifically, a model that we favor has a flow hierarchy which focuses on the stimulated reservoir region with the nanometer-scale matrix pores connected to a network of interconnected micro-fractures and macro-fractures and eventually connecting to the wellbore via hydraulic fractures.

IOR and EOR Issues: Multi-stage hydraulic fracture stimulation of long horizontal wells breaks down the reservoir matrix rock in such a way that large matrix blocks are surrounded by micro and macro fractures. These fractures eventually become connected to the wellbore to provide the flow path for reservoir depletion. For enhance oil recovery the flow path is reversed to carry the injected fluid to the surface of the matrix blocks. The exchange between fracture and matrix is a complicated issue. The injected fluids could include water, chemically augmented water, or a gas (such as CO₂). The problem with EOR in the Bakken is the inability of injected water, or any other fluid, to displace oil from the matrix significantly. Similarly, the effectiveness and cost of the EOR injection fluids is also of concern. The EOR fluids could include methane, nitrogen, CO₂, and low concentration of polymer, alkali and surfactant aqueous solutions. A specific issue with the EOR fluids is their effectiveness, because injected
fluids have to travel long distances through man-made fractures, natural fractures or induced fractures to reach the very low-permeability matrix pores to expel oil from the matrix. Finally, the wettability of the Bakken reservoirs reduce the effectiveness of water flooding, but this negative effect could be partially countered with a favorable contribution from the osmotic pressure across the fracture-matrix surfaces.

While CO₂ injection is widely applied in conventional reservoirs, its use for EOR in tight oil reservoirs is a relatively new concept. In conventional reservoirs heterogeneity, wettability, and the degree of pore uniformity have a significant effect on the effectiveness of an EOR scheme while fractures could be detrimental. On the contrary, in tight oil reservoirs fractures are the major contributors to oil productivity; thus, much of the conventional wisdom does not apply.

1.4 Contributions of the Study

In this research, we discovered that, in addition to matrix porosity, a micro-fracture network provides the main flow channel to enhance primary oil production from Bakken formation. Furthermore, in pursuit of the secondary or enhanced oil production, the micro-fracture network is the main pathway for delivering water or CO₂ to the tight matrix of the Bakken formation. Consequently, a dual-porosity architecture, composed of matrix and the micro-fracture network, was the main reservoir framework for our reservoir modeling and analysis.

1.5 The Organization of the Thesis

This thesis has nine chapters.

Chapter 1 is the introduction, which explains the research plans, objectives, background, problem statements, and the contribution of the research.

Chapter 2 is a global literature review, but pertinent literature reviews are presented in each chapter.

Chapter 3 describes the petroleum geology of the Bakken formation and the surrounding reservoirs in Williston Basin.

Chapter 4 presents the reservoir fluid properties of Bakken formation to include the importance of fluid characteristics in primary production and enhance oil recovery plans.

Chapter 5 describes properties of Middle Bakken formation and the use of supercritical CO₂ for permeability measurement, the benefits of low-salinity fracturing fluids, and the potential application of low salinity for EOR.

Chapter 6 presents well testing methods and their applications in characterization of Bakken formation.
Chapter 7 presents rate transient analysis, incorporating single- and multi-phase flow analyses for the Bakken wells in North Dakota. This chapter also includes the analyses of Elm Coulee Bakken production performance in Montano, which could be used as a guide for the long-term production performance of younger Bakken fields in North Dakota.

Chapter 8 presents the use of a compositional numerical simulation model to assess potential EOR schemes. The chapter explains the model construction and its calibration against pressure and rate transient data via history matching. The reservoir simulation is then used to forecast field performance, both for primary and enhanced oil recovery by waterflood and CO₂ injection.

Chapter 9 provides the conclusions, discussion, and recommendations of the thesis.
CHAPTER 2
LITERATURE REVIEW

Bakken oil play in Williston Basin is one of the largest known oil accumulations in the world. The Bakken formation underlies portion of Montana, North Dakota, Manitoba, and Saskatchewan. The combination of horizontal well drilling and multi-stage hydraulic fracturing has been the key to economically produce the Bakken reserves. As Bakken development continues, primary recovery factor remains rather low. Reservoir characterization is essential to understand the fluid flow in nano-size matrix pores and fractures so that one can perform forecast modeling for primary production through pressure depletion and for enhanced oil recovery by waterflood or gas injection.

Honarpour et al. (2012) presented the best practice methodology for characterizing rock and fluid properties and how their variability can impact on well performance in liquid rich shale reservoirs. Their sensitivity study showed that the rock data can impact initial rate and ultimate recovery includes effective permeability, its anisotropy, its alignment with hydraulic and natural fracture network, and rock-type based compaction. Unconventional PVT behavior was also discussed such as decreased oil bubble point pressure, the resultant viscosity and GOR behavior, and interfacial tension in conjunction with capillary pressure suppression and relative permeability.

The dependence of reservoir permeability and porosity on pressure and its impact on well performance has been studied by many researchers. McKinney et al. (2002) showed that the hyperbolic decline was observed in many tight gas reservoirs due to reductions in permeability and porosity during the depletion. They suggested to measure rock properties under the entire range of expected net stress conditions.

Raghavan and Chin (2004) presented a fully coupled geomechanical and fluid-flow model to analyze pressure-transient responses of wells in stress-sensitive reservoirs. The model was tested by examples with known solutions to verify the numerical accuracy and ability to retain correct physical principles. They provided correlations to evaluate productivity changes in stress-sensitivity reservoirs that may be used for production forecasts.

Archer (2008) presented a solution strategy to evaluate impact of stress sensitivity on production data analysis for a single phase, single porosity reservoirs. Bachman et al. (2011) also discussed the importance of stress-dependent permeability in reservoir characterization and modeling of stimulated horizontal Montrey gas wells. Cipolla et al. (2011) showed that the well productivity can be significantly impaired by stress-dependent network-fracture conductivity in shale gas reservoirs with lower Young’s modulus parameters.
Cho et al. (2012) discussed the effect of pressure-dependent natural fracture permeability on well performances. They used the experimental data from Bakken cores to screen and calibrate the correlations proposed in the literature.

Luffel et al. (1993) presented a permeability measurement for shale using crushed rock samples, also known as GRI technique. This method was developed in order to find an alternative to the plug permeability measurements for shale which were highly affected by the fractures contained within the core plug. They applied pressure pulse on unconfined crush rock particles which were assumed to be crack free. Cui et al. (2009) and Profice et al. (2011) noticed that the permeability measured with this technique depend on the particle size. Tinni et al. (2012) further evaluated GRI permeability technique by designing an experimental program to measure permeability on different particles sizes of same rock under different measurement conditions. They summarized the short comings of the GRI method such as the absence of reservoir effective stress, the potential creation cracks in the crushed samples, and the lack of Klinkenberg correction. All of which result in inconsistent permeability values reported by different laboratories. They proposed to measure permeability on shale plugs instead of crushed rock samples as in GRI technique.

Ramakrishma et al. (2010) applied formation evaluation in the Bakken using laboratory core data and advanced logging technologies in selecting completion intervals. In their study, they used core measurements to understand the mineralogy, formation fluids, and porosities/permeabilities present in Upper Bakken Shale, Middle Bakken, Lower Bakken Shale, and Three Forks. These core data then used to calibrate the logging responses such as NMR and geochemical elemental logs for the reservoir evaluation in the North Dakota Bakken wells.

Besides the impact of rock and fluid properties on recovery, various well productivity trends due to hydraulic fracture stimulation and completion parameters were also studied. LaFollette, et al. (2012) conducted a comprehensive study to analyze well and production data to search for relevant trends in the distribution of production results. Their study includes wells completed in different areas with variety of stimulation methods such as fracturing fluid type and quantity, proppant type and quantity, and completion techniques such as sleeves and packers, plug-and-perforate, completion stages and lengths.

Alcoser et al. (2012) provided a comprehensive summary for history of Bakken petroleum system and describes the successful drilling and completion practices that responsible for current Bakken production. They examined the reservoir characterization and the resource assessments, and discussed about the challenges led by the rapid pace of the Bakken development; including the water supply and handling, the infrastructure, and the environmental sustainability.

With this rapid pace of development, the Bakken reserves estimation has been an ongoing work that keeps updating as the technologies and time evolve. When oil was first discovered in the Bakken
formation, the estimate for original oil in place (OOIP) was approximately 10 billion barrels (Williams 1974). That estimate was revised in 1984 to an OOIP value of approximately 92 billion barrels (Webster 1982). In 1995, the USGS Assessment of Resources estimated only 151 million barrels were technically recoverable. In 2006, the Energy Information Administration (EIA) reported the mean estimate of 413 billion of potential resources in place. USGS estimated a lower value of OOIP in the Bakken to be around 300 billion barrels (Flannery and Krauss, 2006). In 2008, the USGS revised the amount of technically recoverable oil in the Bakken formation at a mean of 3.65 billion barrels. Later in 2008, the state of North Dakota reported 167 billion barrels of oil in place in the North Dakota portion of the Bakken of which 2.7 billion barrels were considered to be technically recoverable with current technology. The 2011 North Dakota Industrial Commission (NDIC) estimated 11 billion barrels of reserves just in North Dakota. The chronology of total oil in place reserve estimation for Bakken petroleum system is summarized by Energy and Environmental Resources (EERC, 2013) in Fig. 2.1:

![Bakken petroleum system total oil in place reserve estimation](image)

**Figure 2.1**: Bakken petroleum system total oil in place reserve estimation (EERC, 2013).

Several studies to estimate ultimate recovery (EUR) and recovery factor for Bakken have been presented. All of which showed that recovery factors for the Bakken is highly uncertain. This may be attributed to the complex flow mechanism between interconnected network of fractures and matrix, and the effectiveness of hydraulic fracturing.

Reisz (1982) used a combination of forecasting methods to compare recoverable reserves from vertical wells with horizontal wells completed in Upper Bakken Shale in the Billings and Mckenzie
counties of North Dakota. He concluded that drainage area and recoverable reserves for a horizontal well are 2.5 to 3.0 times that of a vertical well with recoverable reserves of 200 to 250 MBO for average wells and can 300 to 500 MBO for better wells.

Clark (2009) presented recovery factor for the Bakken in Mountrail County, North Dakota using three different methods. The first method involved review of the published recovery factor estimates, resulted in a mean of 8.8 %; the second method was based on material balance yielding a mean of 7.4 %; and the third method was based on decline curve analysis with an average of 7.1 % recovery factor.

Dechongkit and Prasad (2011) used the material balance method to determine recovery factors for the Antelope, Sanish, and Parshall fields. They reported recovery factor of 16 % for Parshall field, 14.9 % for Sanish field, and 9.2 % for Antelope field.

Cherian et al. (2012) evaluated the impact of petrophysical and geomechanical properties on hydraulic fracture lengths, reservoir connectivity, well performance, and well spacing via numerical simulation model. They further investigated the impact of pressure depletion on connectivity between Middle Bakken and Three Forks. They showed that the timing of Middle Bakken and Three Forks well drilling, well spacing, and hydraulic fracture design have significant impact on EUR. Field recovery ranges from 10.9 % to 14.7 % of OOIP after 25-year of production period.

The study by Rasdi et al. (2012) investigated the vertical communication via a geologic model using core and outcrop data. They used time-lapse geochemistry data to quantify vertical drainage and to allocate production between multiple zones in the reservoir simulation model. After their calibration, a recoverable 650 MBO was reported for a horizontal well in Reunion Bay.

Low recovery factors in a large oil volume remaining in place provide a huge potential for enhanced oil recovery. The challenge with enhanced oil recovery by waterflood is the poor injectivity and the preferentially oil-wet character of Bakken reservoirs. These negative effects have been countered during low salinity frac fluid injection during hydraulic fracture stimulation. This raised the importance of understanding mechanism of low salinity brine injection in Bakken.

Although there has been a great number of laboratory tests were performed to evaluate low salinity waterflood (Tang and Morrow 1999a; Tang and Morrow, 1999; Zhang and Morrow, 2006; Zhang et al., 2007), no experimental work has been published to investigate the low salinity brine effect for Bakken.

The mechanism of oil mobilization with low salinity brine was studied by different investigators. Lager et al (2006, 2007) discussed the role of multicomponent ionic exchange in oil recovery during waterflooding in both clastic and carbonate reservoir. They concluded that clastic reservoirs require low salinity brine to decrease ion binding between oil and clay minerals. Ligthelem et al. (2009) explained the wettability alteration process by low salinity in terms of expansion of electrical double layer effects.
Austad et al. (2010) and RezaeiDoust et al. (2010) proposed a new low salinity EOR mechanism that takes into account the effects of pH and salinity on adsorption of acidic, basic organic components onto different clay minerals, clay properties like ion exchange capacity and selectivity, and oil properties.

Fakcharoenphol (2013) showed that osmotic pressure promotes water-oil counter-current flow to produce oil due to salinity gradient. He concluded that oil recovery is enhanced due to a contribution from the osmotic pressure across the fracture-matrix surfaces.

While waterflooding has an unfavorable injectivity, gas injection such as methane, nitrogen, CO₂ may provide a promising option for increasing the recovery for Bakken. Thus, the recent studies focused on the gas injection evaluation in Bakken via numerical simulation models. In the discussion below, it is important to realize different modeling approaches for specific Bakken areas.

Wang et al. (2010) assessed CO₂ flooding potential for Bakken formation in Saskatchewan. They built a single porosity homogenous model with 13 horizontal wells, of which 9 already had about 2-year of production history. They calibrated their model against the historical performance and used the calibrated simulation model to forecast oil recovery factors from primary depletion, waterflooding, and several forms of miscible CO₂ flooding. Their simulation results indicate that the CO₂ flooding after primary production perform much more effectively than continuous waterflooding.

Shoaib and Hoffman (2009) presented single porosity, black oil, and solvent models to evaluate CO₂ flooding in Elm Coulee field, Montana. They showed that recovery factors from CO₂ flooding from homogeneous and heterogeneous models are almost similar. Their study indicated that horizontal CO₂ injection is more efficient over vertical injection, and increases the field recovery factor by 16 % after eighteen years of injection. Hoffman (2012) extended this study to evaluate economic feasibility of other miscible and immiscible gas injection cases besides CO₂. He concluded that significant oil can be recovered regardless of the type of gas injected even if the gas is not miscible with the reservoir oil. Gas injection increased recovery 5 to 10 % in addition to primary production.

Iwere et al. (2012) extended the model presented by Cherian et al (2012) to investigate enhanced oil recovery in Middle Bakken and Upper Three Forks. Multi-well models with 29-stage frac completion were used to investigate natural depletion, waterflooding, and continuous CO₂ injection. They concluded that injectivity of Middle Bakken and Three Forks is very poor regardless of the injected fluid. For Middle Bakken, natural depletion, continuous CO₂ flooding, and waterflooding yield recovery factors of 6.4%, 7.0%, and 6.7 % of the OOIP.

Chen et al. (2013) studied the effect of heterogeneity on improved shale oil recovery by CO₂ huff and puff. In their simulation model, they used log-normally distributed and Dykstra-Parsons function to represent the permeability heterogeneity. This approach did not include the simulation of fracture spacing, fracture conductivity, and fluid flow in naturally fractured reservoirs. Their simulations show that primary
recovery outperforms CO₂ huff and puff in an ideally homogenous reservoir because injected CO₂ moves deep into the reservoir without much increase in near-well pressure. In heterogenous case, CO₂ huff and puff outperforms primary recovery if there exists a low permeability region which keeps CO₂ in the near-wellbore injection region.

Wan et al. (2013a) used a numerical simulation approach to evaluate EOR potential in fractured shale oil reservoirs by cyclic gas injection. In their first study, they have investigated the impact of different well operating schedules, degree of in-situ miscibility between solvent and oil, and propped planar hydraulic fracture spacing on the well primary and secondary production. This study neglected the contribution from the fracture network. They extended this work to study the effect of fracture network spacing, the size of stimulated reservoir volume (SRV), and fracture conductivity (Wan et al., 2013b). Their current model is based on a dual permeability approach to allow fluid communication between matrix and fracture. They concluded that maximizing the stimulated fracture network density has significant impact on the production profiles more than maximizing fracture conductivity. This increased fracture spacing could increase oil production for primary depletion and brought more benefits to the enhancing oil recovery by cyclic gas injection due to increased contact volume between injected solvent with crude oil.
CHAPTER 3

GEOLOGY OF BAKKEN OIL RESERVOIRS

This chapter is a description of the petroleum geology of the Bakken formation and the surrounding reservoirs in Williston Basin. The Bakken story relies heavily on key fields: Antelope, Elm Coulee, Parshall, Sanish, and a Bakken Research Area in North Dakota. Bakken description will include petrophysical properties, petro-facies, and petroleum system.

3.1 Geology of Bakken

Bakken, with an estimated oil in place of 100 to 900 billion barrels, is the most productive oil-producing formation in the Williston Basin and one of the most prolific low-permeability reservoirs in North America. The Williston Basin is a large sedimentary basin that covers parts of North Dakota, Montana, South Dakota, Saskatchewan, and Manitoba (Fig. 3.1).

![Figure 3.1: Bakken Formation in Williston Basin (Sorensen et al., 2010).](image)

The Bakken formation in the U.S. portion of the Williston Basin (Fig. 3.1) produces oil from numerous reservoirs in North Dakota Antelope field (1953), Montana Elm Coulee field (2000), and North Dakota Parshall and Sanish fields (2006). Elm Coulee is the most productive Bakken field producing mainly from the Middle Bakken member of Bakken Formation. Its discovery and successful development set the stage for further exploration leading to other discoveries in Williston Basin in 2006 to include
The Williston Basin is a structurally simple cratonic (i.e., stable) basin with flat-lying sediments (Price, 1999). It is characterized by relatively few and subtle structural features (LeFever, 1991). The prominent structural features in North Dakota are the Nesson and Billing anticlines shown in Fig. 3.2. The Nesson anticline in northwestern North Dakota is the dominant tectonic structural feature around which the early fields (Antelope, Parshall and Sanish in North Dakota) were developed.

The Bakken formation (Fig. 3.3) was deposited during the Upper Devonian and Lower Mississippian periods (approximately 417 to 350 million years ago) (EIA, 2006). It has a maximum thickness of 140 ft (Tran, 2011), and ranges from 3100 to 11000 feet in depth (EIA, 2006). Stratigraphically, the Bakken formation is comprised of three members: the lower member, the middle member, and the upper member. The lower and the upper members of the Bakken Formation were
deposited in a stratified hydrologic regime in an offshore marine environment during periods of sea-level rise. Following the deposition of the lower shale and a rapid sea level drop, the middle member was deposited in a coastal regime. The siltstone lower portion of the middle member was deposited in an offshore, shallow water marine environment while the sandstone middle portion of the middle member was deposited in tidal channels and shoal environments, and the well sorted beds of gray siltstones and very fine grained sandstones in the upper portion of the middle member were deposited in a marine environment with strong current action (Pitman et al. 2001).

Figure 3.3: Williston Basin and North Dakota Bakken stratigraphy (Sorensen et al., 2010).

The upper and lower members of the North Dakota Bakken Formation consist of a dark-gray to brownish black, competent and massive to fissile, slightly calcareous, organic-rich shale (Pitman et al., 2001). These shales are potential source beds for the Middle Bakken, Three Forks, Lodgepole, and Mission Canyon formations (Meissner et al., 1978). The upper and lower member are organic-rich, with total organic carbon (TOC) contents ranging from 12 to 36 weight percent, averaging 25 to 28 percent over large parts of the basin (Tran, 2011). Both these shale members contain a high concentration of Type II kerogen and the source rocks for the petroleum in the Bakken formation (EIA,
The middle member is organic-poor, with TOC contents of 0.1 to 0.3 percent by weight (Price, 1999). The lithology of the Middle Bakken varies widely from clastics (including silts, and sandstones) to carbonates (primarily dolomites), with five distinct lithofacies typically identified in the North Dakota portion of the Williston Basin (Nordeng et al., 2010). In general, all of these rocks are characterized by low porosity and permeability (Pitman et al., 2001). The Bakken formation overlies the Three Forks formation which consists of shale, dolostone, siltstone, sandstone, and a minor occurrence of anhydrite with a maximum thickness of 250 ft. The Bakken formation underlies the Lodgepole formation which has a maximum thickness of 900 ft. Lodgepole consists of limestone and calcareous shale, with small amounts of chert and anhydrite.

Figure 3.4 shows the log suite of gamma ray, resistivity, and porosity for a typical well in the North Dakota Bakken. In this example of a typical well, the gross thickness of the Middle Bakken is 35 ft, the average porosity is 4.8\%, and the water saturation is around 46\%; the average resistivity in the target formation is around 26 ohm-m. The Middle Bakken formation in North Dakota has five facies, the target facies being the laminated one.

**Figure 3.4:** Typical well logs for the Bakken in North Dakota showing each stratigraphic unit (Lodgepole, Upper Bakken, Middle Bakken, Lower Bakken, and Three Forks) with five facies description of the Middle Bakken Formation.
The Montana Bakken also consists of three informal members. However, the typical well in the Middle Bakken in Montana has a higher volume of silty dolostone which provides a higher porosity (7.4%) compared to a typical well in the Middle Bakken in North Dakota (4.8%). Additionally, the lower Bakken shale is typically not present in the Elm Coulee field, as seen in the typical Elm Coulee well log in Fig 3.5 prepared by Brehm (2013). Lower Bakken member in the Elm Coulee well consists of organic-rich siltstone to mudstone which thins locally to the south of the field. In the target Middle Bakken member of the Elm Coulee field, not all five facies are present, as the packstone and lower members are absent. In comparison to high water saturation (46 %) in a typical North Dakota Bakken well (Fig. 3.4), the average water saturation for the typical Elm Coulee well is around 14 % (Fig. 3.5). This also results in higher average resistivity, 150 ohm-m in the typical Elm Coulee well. The high porosity, high resistivity, and low water saturation observed in Elm Coulee suggest more oil wet types of rock in Elm Coulee Bakken than the North Dakota Bakken.

![Figure 3.5: Typical well logs for the Bakken in Elm Coulee, Montana showing each unit (Lodgepole, Upper Bakken, Middle Bakken, Lower Bakken, and Three Forks) with three facies description of the Middle Bakken Formation.](image)

### 3.2. Petrophysical Properties of North Dakota Bakken

The middle member of Bakken formation and upper Three Forks formations have been the focus of oil and gas production in Williston Basin. The hydrocarbon charge comes from upper and lower member of organic-rich shales which expelled oil into middle Bakken as well as into the lower Lodgepole
and upper Three Forks formation. **Figure 3.6** shows a suite of logs from a Bakken well in North Dakota which includes gamma ray, resistivity, neutron-density, log-derived water saturation, and core measurements and petrophysical facies. The last two columns in **Fig. 3.6** compare the log-derived water and hydrocarbon saturations versus the core-derived saturations.

The gamma ray is used to identify shales and clays which have different gamma ray signatures due to variation of natural radioactivity. The formation layers are identified from the gamma ray response to include Lodgepole, False Bakken, Scallion, Middle Bakken, and Three Forks. These formations are significantly different from the upper and lower Bakken shales. The subdivision of each formation into petrophysical facies is also accomplished from log details as shown on **Fig. 3.6** (Buckner et al., 2012). For example, the figure shows five facies in the middle Bakken where **lithofacies 3** in middle Bakken is the target production zone.

**Figure 3.6:** An example of a suite of logs which identifies various formations, and petrophysical facies in North Dakota Bakken (Modified from Chen et al., 2012).
The lateral resistivity includes both deep reading in red (40 to 60 inches into the formation) and the shallow reading in blue (10 to 25 inches into the formation). The resistivity in the upper and lower Bakken shales is large because of presence of oil in the microspace. However, in middle Bakken, the pore space is partially filled with salt formation brine and with a lower resistivity around 15 to 20 ohm-m. When neutron and density log readings are about the same, it is indicative of limestone with a bulk density of 2.71 g/cm³. In Lodgepole, neutron log readings are higher due to the presence of brine.

Middle Bakken is composed of three different lithologies including sandstone (2.65 g/cm³), limestone (2.71 g/cm³) and dolomite (2.85 g/cm³). The average density of these three lithofacies is around 2.73 g/cm³ results in a density trend of a limestone response. As shown in Fig. 3.6, the upper part of middle Bakken, Lithofacies 5, is more dolomitic and the neutron and density logs are separated. The neutron and density logs are used to calculate porosity while formation resistivity and porosity are used to determine water saturation. The blue line represents water saturation derived from Archie’s equation. The oil saturation in red and the water saturation in green are calculated from the core measurements. The results indicate higher water saturation in Lodgepole than in Scallion, Middle Bakken and Upper Three Forks. The latter has the lowest water saturation among all of the shale formations in the Bakken sequence. The Middle Bakken and Upper Three Forks have an average of 50% of water and 50% oil saturations, whereas the Middle Three Forks formation has very little oil saturation.

3.3. Petro-facies of North Dakota Bakken

Various well log signatures can be used to subdivide each formation layers into petrophysical facies as shown in Fig. 3.6, where the identified facies include LP1, LP2, FB, SCAL, UB, MB5, MB4, MB3, MB2, MB1, LB1, LB2, TF1, TF2, TF3.

Lodgepole formation has a maximum thickness of 900 ft consisting of limestone and calcareous shale, with small amounts of chert and anhydrite. Figure 3.7 shows the core pictures from Lodgepole-1 (LP1), Lodgepole-2 (LP2), False Bakken (FB), and Scallion (SCAL) units. LP1 is intercalated skeletal lime mudstone and argillaceous lime mudstone which displays slightly lower gamma ray in comparison with LP2 (Fig. 3.6). Lower Lodgepole includes False Bakken and Scallion units. The contact at the base of LP2 facies is sharp with respect to False Bakken unit. The FB unit is dark brown to gray, laminated to homogenous shale overlaying the Scallion member. SCAL unit is a clean limestone interval (slightly argillaceous limestone to clean lime mudstone) above the Upper Bakken shale which is identified by a distinctive gamma signature.

The Middle Bakken formation comprises a series of complex lithofacies with variable distribution and properties. The variation in geomechanical properties of the various Bakken members and lithofacies is the key to oil productivity, because this variation dictates the size, frequency, pattern, and orientation
of fracture (natural and artificial) network at both the micro- and macroscale. Vertical heterogeneity in Middle Bakken is directly tied to the occurrence and nature of the lithofacies. The Middle Bakken has been the primary target for horizontal drilling and is the focus of this research.

![Figure 3.7: Core pictures showing the lithofacies of Lodgepole 1, Lodgepole 2, False Bakken and Scallion in North Dakota Bakken.](image)

In a 2012-2013 joint project with the Energy and Environmental Research Center (EERC, 2013) in North Dakota, a series of petrographic analyses were completed on each interval from three Bakken wells in Bailey field. These analyses included X-ray diffraction (XRD), X-ray fluorescence (XRF), optical microscopy (OM), and scanning electron microscopy (SEM). Figure 3.8 provides the stratigraphy of five Middle Bakken lithofacies identified in these wells.

**MB5** lithofacies is a massive, dense, mottled, dolomitic siltstone. Thin section, XRD, and SEM analyses indicated that MB5 is largely dominated by quartz, feldspar, and clay (accounts for over 60% of the minerals) with a few calcareous clasts and dolomite cement, to a rock dominated by dolomite and calcite (over 50%) cementing quartz grains that account for approximately 30% of the mineralogy. Clays can account for over 10% of the mineral content, with illite being the primary clay. Pyrite grains (although considered to be a minor constituent) were also observed to occur in greater amount than the other Middle Bakken lithofacies. Porosity in the MB5 is generally observed only within fractures, though some trace interparticle porosity was observed in some samples. Helium gas porosity of MB5 ranges from 0.28 to 5.5%.
MB4 lithofacies in the Bailey field study area is often referred as the “packstone facies” thickness ranges from 2 feet in the southwest portion of the study area to over 12 feet in the central and northern portions. This lithofacies is considered by some to be one of the more oil productive zones within the Middle Bakken. MB4 can generally be subdivided into 2 to 4 distinct subzones. In the study area MB4 can be divided into carbonate dominated zones in the bottom half of the zone, overlain by a 1- to 3-ft thick zone of laminated, sometimes bioturbated, fine-grained sandstone, which in turn is topped by another carbonate packstone. The packstone subzones are generally described as being sandy skeletal, sometimes oolitic grainstones. The lower zones are generally calcite cemented while the uppermost zone is slightly dolomitic. Thin section, XRD, and SEM analyses indicated that calcite is the dominant mineral (up to 80% in some samples) in MB4 with quartz and dolomite grains accounts for a vast majority of the remaining mineral content. Clays generally account for less than 1% of the mineral content, with illite being the primary clay. Porosity of the carbonate-dominated MB4 is observed only within fractures. Porosity measurements of core plugs, using helium gas, showed MB4 porosity ranges from 0.77 to 1.41%. Thin section analysis indicated that the observed porosity is limited to microfractures, with SEM measurements of microfracture aperture ranging from 2.4 to 8.0 µm.

MB3 lithofacies sometimes referred as the “laminated facies” is an interbedded sandy and silty dolostone and argillaceous dolomitic mudstone. In the Bailey field, the laminated facies is often the drilling target for the horizontal leg of Bakken wells. Along with MB4, MB3 is considered an important zone of oil productivity within the Bakken. The thickness of the laminated facies in the Bailey field area ranges from 7 to 15 ft in thickness, with the thickest occurrence being in the southwest portion of the study area. Thin section, XRD, and SEM analyses indicated that quartz is the dominant mineral (up to 50% in some samples) in Lithofacies 3 with calcite and dolomite cements accounting for up to 30% of the mineral content. Clays generally account for less than 10% of the mineral content. Illite accounts for a majority of the clay, although some smectite and chlorite were identified. Thin section analysis showed that the Laminated Facies includes intraparticle, interparticle, and fracture types of porosity. Helium gas porosimeter measurements on core plugs showed MB3 porosity ranges from 3.2 to 5.03%. Thin section analysis of MB3 indicated that observed porosity was limited to microfractures, with SEM measurements of microfracture aperture ranging from 3 to 17 µm.

MB3 can be further subdivided into two or three different zones, depending on the well. These subzones are marked by changes in porosity (as seen in well logs and most noticeably in gamma ray logs) and are observed in core as zones where laminations become more numerous and uniform towards the base of MB3. Determining the relative thickness and distribution of the highly laminated zones in MB3 is of interest for predicting the intrusion of injected CO2 into the pores. The laminated zones of MB3 not only display slightly higher porosity, but also are generally geomechanically weaker than other
Bakken lithofacies and therefore more prone to fracturing during the well stimulation process. This combination of characteristics suggests that CO₂ will move more easily through this portion of the reservoir, a phenomenon that must be considered when designing a CO₂ injection.

**Figure 3.8:** Representative stratigraphy of the Middle Bakken Formation and a brief description of five Middle Bakken lithofacies (MB5, MB4, MB3, MB2, MB1).

MB2 lithofacies is a brownish gray argillaceous siltstone that is sometimes referred as the “burrowed lithofacies” because of its moderately to strongly bioturbated nature. In the Bailey field study area it ranges from 11 to 16 ft in thickness, with the thickest occurrence being in the center of the area. Thin section, XRD, and SEM analyses indicated that quartz and illite are generally the dominant minerals in MB2, though some thin sections were dominated by calcite. Helium gas porosimeter measurements on core plugs showed MB2 porosity ranging from 1.32 % to 3.75 %. Thin section analysis indicated that observed porosity was limited to microfractures, with SEM measurements of microfracture aperture ranging from 3.0 to 17 µm.

MB1 lithofacies is a transitional facies from the anoxic environment that deposited the Lower Bakken black shale into a normal marine setting. In the Bailey field study area, MB1 is an argillaceous
siltstone ranging in thickness from very thin (less than 1.5 ft) in the north and the south, to non-existent in the center. Thin section and XRD analyses show that it is dominated by quartz and calcite, including bioclasts, with occasional dolomite and feldspar occurrence and trace amounts of pyrite, muscovite. Illite is the dominant clay, comprising as much as 10% of the mineral composition. The fabric of MB1 is generally massive, dense, and somewhat mottled in appearance. Helium gas porosimeter measurements on MB1 core plugs indicated that porosity varies from 2.73 to 3.87%. **Thin section analysis of MB1 indicated that observed porosity was limited to microfractures, with SEM measurements of microfracture aperture ranging from 5 to 10 µm.**

![Figure 3.9: The core pictures showing the lithofacies of TF1, TF2, and TF3 in North Dakota Bakken.](image)

The Bakken formation overlies the Three Forks formation, which consists of shales, dolostones, siltstones, sandstones, and minor occurrence of anhydrite with a maximum thickness of 250 ft. Upper Three Forks has three lithofacies TF1, TF2, and TF3 shown and described in **Fig. 3.9. TF1** (known as Pronghorn) is the bioturbated silty dolomite and sandstone, which sometimes has the upper contact with the Basal Bakken when present. This unit overlays the TF2 unit, which is also known as turquoise member. It is very thinly bedded green claystone and brown to tan dolomitic siltstone (**Fig. 3.9**), which provides higher porosity than Middle Bakken target facies (MB3) as interpreted in log analysis (**Fig. 3.6**). The TF2 facies, also known as chocolate shale, overlays the TF3 unit. **TF3** is the structureless, slightly
laminated, reddish silty claystone. In recent years, beside Middle Bakken production, the Upper Three Forks has been the target for the horizontal drilling.

3.4. Potential for Petroleum Reservoirs in North Dakota Bakken

In this section hydrocarbon-bearing formations that have production potential in the Greater North Dakota Bakken were identified. This includes production from Lodgepole, Scallion, Middle Bakken and Three Forks formations. To accomplish this, several horizontal wells in Murphy Creek, Bailey and Reunion Bay fields were studied at core, well, and field scales.

This section describes the lithofacies and the technical background of oil production potential from each formation. Middle Bakken and Three Forks formations have been the focus for the development in the Williston Basin, whereas only few wells have been drilled to explore the potential of hydrocarbon production from Lodgepole and Scallion formations. Figures 3.10 to 3.12 show oil production, gas-oil ratio, and water cut versus cumulative oil production for the several horizontal wells drilled in Lodgepole, Scallion, Middle Bakken, and Three Forks in the study area. The observations from these plots are discussed below:

The Lodgepole formation has the lowest cumulative oil production, in spite of the fact that it produced a high initial flow rate followed by a sharp decline (Fig. 3.10). The Lodgepole well has a 7-stage completion in a 5000-foot lateral and was drilled in Murphy Creek field in 2009. The mini-frac test from this well gives a pore pressure of 4852 psi (0.45 psi/ft) and suggests a pressure-dependent leak-off characteristic. In Middle Bakken, the pore pressure is nearly twice as the Lodgepole. The effective permeability estimated from mini-frac and the rate-transient analyses in the Lodgepole well is between 0.07 to 0.1 md. The flow rate decline analysis falsely indicates an existence of a nearby boundary caused by fracture closure.

The producing GOR in the Lodgepole well is around 700 MSCF/STB, which is higher than the GOR of 450 MSCF/STB in the offset Middle Bakken wells in this area (Fig. 3.11). In the petrophysical property section, the water saturation calculated for the Lodgepole logs was higher than that in other formations. This is also confirmed by the high water cut (0.48) from the Lodgepole well (Fig. 3.12).

In summary, the rapid decline in oil flow rate, large WOR and GOR, and presence of fractures in cores (Fig. 3.7) suggest there are significant amount of stress-dependent fractures existed in Lodgepole formation. These parameters also suggest that Lodgepole development is economically questionable.

Scallion formation has a better oil production rate than Lodgepole well, shown in Fig. 3.10. This can be explained because of increased porosity in Scallion's clean limestone section. The mini-DST conducted in this well yields an effective permeability of 0.1 md due to the presence of micro-fractures in Scallion formation. Scallion has also high water saturation but higher porosity and more movable oil than
Lodgepole. The mini-frac test shows pressure-dependent leakoff coefficient with a lower pore pressure of 5154 psi (0.51 psi/ft) than that of Middle Bakken. Higher effective permeability and pressure-dependent leak-off coefficient are indicative of a naturally fractured system in Scallion formation because both mini-DST and mini-frac tests were conducted before implementing hydraulic fracture stimulation. Scallion has a higher porosity than Lodgepole, water cut is around 0.52, and producing GOR is around 300 MSCF/STB. To develop Scallion Formation only a small number of multi-stage completions may be necessary because of the presence of an extensive natural fracture system. In addition, vertical well drilling and completion may be an economic option.

![Figure 3.10: Oil productivity behavior of six wells in the Greater North Dakota Bakken.](image)

Middle Bakken wells demonstrate definite regional oil productivity variations due to the differences in rock and fluid properties in Murphy Creek, Bailey, and Reunion Bay fields. The lateral length of each Middle Bakken well is around 9000 ft. The well in Murphy Creek field (2009) and well in Bailey field (2009), each has a single-stage, open-hole completion while the well in Reunion Bay (2012) has 30-stage swellable packer completion. Average producing GOR is increasing from Murphy Creek (south) to Bailey and to Reunion Bay area (north), with 400 to 500, and to 800 MSCF/STB,
respectively. Regardless of change in oil production, the water cut is very consistent in each area and stays constant around 0.2 during the depletion.

![Figure 3.11: GOR behavior of six wells in the Greater North Dakota Bakken.](image)

Various well tests including mini-DST, mini-frac, and pressure buildup tests were conducted in the Middle Bakken Formation (Chapter 6). Overall, the average effective permeability of Middle Bakken from these tests is around 0.01 to 0.07 md with a pressure gradient of 0.73 to 0.75 psi/ft. These results indicate that the field-measured permeability was several orders of magnitude greater than the permeability measured on core plugs (10^{-4} to 10^{-5} md) (Chapter 5). Due to higher initial pressure and the overpressure nature, the Middle Bakken formation has a better oil productivity potential than Lodgepole and Scallion formations. Oil production from Middle Bakken formation can be enhanced with advanced in completion technology and enhanced oil recovery schemes.

Upper Three Forks formation has small water saturation (mostly irreducible) and higher porosity than the Middle Bakken formation because of a greater dolomite content. The Three Forks well (Fig. 3.10-3.12), was drilled in 2012 in Reunion Bay field. This well has a 9200-foot well length and is stimulated with a 30-stage completion. This Upper Three Forks well has a slightly higher water cut (0.3) than the Reunion Bay Middle Bakken well (0.2) while the GOR is nearly the same (800-900...
MSCF/STB). Mini-frac test results shows an effective permeability of 0.03 md which has the same order of magnitude as that of Middle Bakken wells, and much higher than the laboratory measured core permeability. In Reunion Bay area, the Upper Three Forks well has equal or better production performance in comparison with the Middle Bakken wells. Overall, the performance of the Middle Bakken and Three Forks wells exhibit better and sustainable production because of the presence of micro-fracture and better matrix porosity.

**Figure 3.12**: Water cut behavior of six wells in the Greater North Dakota Bakken.
CHAPTER 4

RESERVOIR FLUID PROPERTIES

This chapter summarizes the fluid properties of Middle Bakken Formation in Reunion Bay, Bailey and Murphy Creek fields. It is essential to understand the impact of fluid characteristics during primary production and possible oil recovery processes. This information is used to model fluid flow in each area and explore the interaction between fluid-fluid during CO₂ injection and rock-fluid during low-salinity hydraulic fracturing in a high salinity formation brine environment.

The sections below include the fluid phase behavior in nano pores, pressure/volume/temperature (PVT) experiments and model properties, SARA analyses, total acid number and water content of Bakken oil, and the produced reservoir water properties.

4.1 Oil Properties

This section contains the fluid characterization for the study areas. Recombined separator fluid samples from different area were characterized to provide the variation in bubble point pressure, gas-oil ratio (GOR), oil density, oil compressibility and viscosity. Pressure and temperature phase envelop and constant liquid volume lines are shown to demonstrate how this oil system favors the expansion drive.

4.1.1 Fluid Phase Behavior in Nano Pores

Several literatures have investigated pore-dependence fluid properties in unconventional reservoirs; however phase behavior and property changes in nanopores are still hypotheses. Honarpour’s study (2012) suggests phase behavior in liquid rich shale reservoirs behave differently from conventional reservoirs. For the phase behavior of the reservoir fluid in a PVT cell, the gas molecules are ready to be released below saturation pressure, representing gas evolution from oil in larger pores as in conventional reservoirs. However, in a pore of nanometer scale, the radius of curvature of a nucleated gas bubble is restricted by the size of the pore. This results in the formation of bubbles with high curvature which requires an enormous pressure differential across the interface to sustain a stable bubble.

For example, the laminated lithofacies of Middle Bakken has a pore size of 0.02 microns (20 nm) as reported in Ramakrishna et al.’s study (2010). With an average water saturation of 50% for Middle Bakken based on the petrophysical properties (Section 3.2), 50% of the pore volume is filled in with water on the rock wall leaving a pore diameter of 15.8 nm. The pressure differential due to the interfacial tension for a gas bubble with a radius of 7.9 nm can be calculated using the following equation:
\[ p_g - p_o = \frac{2 \sigma_{go} \cos \theta}{r} \]  

Where \( p_g \) and \( p_o \) are gas and oil phase pressures, \( \sigma_{go} \) is the interfacial tension between gas and oil phases, \( r \) is radius of curvature of the gas-oil interface, and \( \theta \) is the contact angle. For a gas-oil system, interfacial tension is 4 dyne/cm (\( \sigma_{go} = 4 \text{ dyne/cm} \)) and the contact angle is zero (\( \theta = 0^\circ \)) (Archer and Wall, 1986). For a gas bubble radius of 7.9 nm, the pressure differential was calculated to be 146 psi. This is the capillary pressure needs to be overcome to form a gas bubble in a 20.0 nm pore. This delayed process of gas bubble formation in nano pores lowers the bubble point pressure lower than the bubble point measured by PVT cell. Figure 4.1 demonstrates the change in the pressure-temperature phase diagram, formation volume factor, and gas-oil ratio behavior for nano pores compared with those in a bulk cell (PVT test).

![Schematic Phase Diagram - Bulk vs. Nano Pores](image)

**Figure 4.1:** Bulk versus nano pores: P-T phase diagram, oil formation volume factor, and gas-oil ratio (Honarpour, et al., 2012).

In addition to the matrix nano-pore size, reservoir connectivity due to the existence micro- and macro-fractures and high initial reservoir pressure should also affect the fluid flow behavior in unconventional reservoirs. GOR is expected to be higher in more fractured area due to increased surface area associated with a complex fracture geometry.

In summary, the delay in wells to respond to lower BHP can be explained due the following effects: the nano-size pore structure, the fracture network and matrix contribution in the long-term, and the high average pore pressure in the reservoir.

### 4.1.2 PVT Experiments

In order to determine the phase and fluid characteristics in a PVT cell, separator gas and oil were collected from eight wells in the Murphy Creek, Bailey, and Reunion Bay fields. Seven of them were from Middle Bakken wells and one of them was from a Three Forks well. Most sampling was done before
the pump installation. This took place in the early life of the well after the hydraulic fracture stimulation where the producing gas-oil ratio was stabilized. The stable GOR also suggests that the near-wellbore is still maintaining above a bubble point pressure. The collected separator gas and oil samples were then recombined at a representative producing separator gas-oil ratio.

The volumetric changes of the reservoir fluids as a function of pressure depletion were obtained by PVT experiments including constant-mass expansion (CME) and differential liberation (DL) at reservoir temperature. Table 4.1 summarizes the results from the single-stage flash test at standard conditions (14.7 psi and 60 °F). Live oil compressibility and viscosity values were determined at bubble point pressure. The average bubble point pressure and solution gas-oil ratio obtained Middle Bakken fluid samples are; 2400 psi and 870 SCF/STB in Reunion Bay; 2000 psi and 600 SCF/STB in Bailey; and 1500 psi and 460 SCF/STB in Murphy Creek.

Table 4.1 Single-stage flash test summary for eight Bakken recombined fluid samples

<table>
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<tr>
<th>Field Name</th>
<th>Well #</th>
<th>Sample Formation</th>
<th>Properties at Bubble Point Pressure (P_b)</th>
<th>Single Stage Flash (Standard Condition)</th>
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<td></td>
<td></td>
<td>T_r, °F</td>
<td>P_b, psia</td>
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<td>Middle Bakken</td>
<td>212</td>
<td>2304</td>
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<tr>
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<td>Middle Bakken</td>
<td>237</td>
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<td>1753</td>
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<td>Middle Bakken</td>
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<td></td>
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<td>Middle Bakken</td>
<td>240</td>
<td>1389</td>
</tr>
</tbody>
</table>

Before tuning the Equation-of-State (EOS) parameters, the Peng-Robinson 78 (PR-78) equation of state with Peneloux volume shift correction was used to generate the phase envelope for each sample. Figure 4.2 illustrates the pressure-temperature (PT) phase envelopes for one sample from each area with the corresponding bubble point pressure contour map generated from all the samples listed in Table 4.1. The bubble point pressure is increasing from south to north of the study area.

Figure 4.3 plots the phase envelopes of each fluid with the constant liquid volume % with both reservoir and surface conditions. As expected in a black oil system, these quality lines are spaced fairly evenly within the envelope. The average initial reservoir pressure is between 7500 psi and 8000 psi and the reservoir temperature is 240°F. At reservoir temperature, the pressure difference between the reservoir and the bubble point pressure is higher for Murphy Creek than Bailey and Reunion Bay.
Figure 4.2: PT phase envelopes for three areas: Reunion Bay (green), Bailey (red) and Murphy Creek (blue).

(a) Reunion Bay field
(b) Bailey field
(c) Murphy Creek field

Figure 4.3: Phase diagram of Bakken samples in three fields with iso-vols and lines of isothermal reduction with both reservoir and surface conditions.
Figure 4.4 plots the solution GOR of each test against the pressure as well as the corresponding GOR contour-map. The solution GOR has an increasing trend from Murphy Creek (South-West) to Reunion Bay (North-East).

![Figure 4.4: Solution-GOR trend for three areas: Reunion Bay (green), Bailey (red) and Murphy Creek (blue) and gas-oil ratio contour map.](image)

Figure 4.5 shows the oil density, oil viscosity, formation volume factor, and oil compressibility for each fluid. The samples in Reunion Bay field are listed in green, Bailey field in red, and Murphy Creek field in blue. The oil density (a) and oil viscosity (b) are decreasing from Murphy Creek field (south) to Reunion Bay field (north), whereas both the formation volume factor (c) and oil compressibility (d) are increasing. Reunion Bay has the best oil quality with the lowest oil density, lowest viscosity, and highest GOR, among the three areas.

The fluid characterization was done by regressing EOS parameters. Because un-tuned EOS may be unable to predict properties at reservoir conditions, PVTsim (Calsep, 2011) fluid characterization software was used to tune EOS parameters against lab data measured at reservoir conditions. Tuned EOS parameters for plus components ($C_7^+$ in this study) include acentric factor, $A_c$, critical temperature, $T_c$, critical pressure, $P_c$, the Peneloux volume-shift factor, $Cpen (=c$ in EOS), EOS coefficients of $\Omega_a$, and $\Omega_b$, and binary interaction coefficient between components, $k_{ij}$. 
Figure 4.5: Bakken PVT data comparison in three areas: Reunion Bay (green), Bailey (red) and Murphy Creek (blue) field.

The PR-78 with Peneloux volume shift factor (Eq. 4.2) used to match the predicted properties against the lab measured data.

\[
P = \frac{RT}{V-b} - \frac{a(T)}{(V+c)(V+b+2c)+(b+c)(V-b)} \tag{4.2}
\]

Where \( R \) is the gas constant; \( T \) is the absolute temperature; \( P \) is the pressure; and \( V \) is the molar volume. \( a \) is a function of \( (A_o, T_o, P_o, \Omega_o)_o \), \( b \) is a function of \( (T_o, P_o, \Omega_b)_o \), and \( c \) is the Peneloux volume-
shift factor. ‘i’ represents the component number and goes until ‘n’, total number of components to include binary interaction coefficient between component \( i \) and \( j \), \( k_{ij} \).

![Figure 4.6: Bakken molar composition for all the fluid samples.](image)

For illustration, the fluid characterization of the second fluid sample from Reunion Bay (Table 4.1) is presented. This sample presents the fluid properties used in the compositional reservoir simulation in Chapter 8. First, fluid composition and PVT laboratory data were entered in the software, PVTsim (Calsep, 2011). QA/QC was undertaken to confirm if the predicted GOR, API and bubble point agrees with the lab measured data.

Two types of tuning were applied including plus-fluid and characterized-fluid regression. In the preliminary tuning (plus-fluid tuning), property correlations were tuned to ensure reasonable trend of EOS parameters. This was followed by the characterized fluid tuning which allows tuning individual EOS parameters to further improve the regression quality. Figure 4.7 illustrates the final-tuned EOS predicted properties versus lab measured data for constant-mass expansion and differential liberation tests.

Using the tuned EOS parameter, Lohrenz-Bray-Clark (LBC) correlation (1964) coefficients and critical molar volume were then adjusted to match lab measured viscosity. Figure 4.8 shows the final viscosity match for the Bakken sample. And the gas viscosity was simply predicted by the Corresponding-State method (Pedersen and Christensen, 2007). The final characterized EOS fluid model was used to generate PVT tables for the reservoir simulation.
**Figure 4.7:** Bakken Sample # 2 (Table 4.1) before and after regression to CME and DL in comparison with the laboratory data.

**Figure 4.8:** Viscosity before and after regression compared with the laboratory data.
4.1.3 SARA Analyses

The existence and the stability of asphaltene in crude oil should be examined to determine the risk of asphaltene precipitation because it can cause operational issues in the reservoir. Precipitation of asphaltene can cause constriction of fluid flow passages or injectivity problems associated with wettability reversal.

Therefore, saturate, aromatic, resin, and asphaltene analysis was conducted to identify crude oil components according to their polarizability and polarity. The saturate fraction consists of nonpolar material while aromatics are slightly more polarizable. Both resins and asphaltene have polar substituents. The importance of polar components for crude oil to be adsorbed onto clay minerals will be discussed in Chapter 5.

There are three common techniques for SARA analysis which are summarized below:

1. Thin layer chromatography (TLC): TLC involves a stationary phase of a thin layer of adsorbent like silica gel on a flat, inert substrate. This is the fastest separation method. Asphaltenes do not need to be separated from other crude oil components before chromatographic analysis (Fan et. al, 2002).

2. High performance liquid chromatography (HPLC): The sample is forced by a liquid at high pressure (the mobile phase) through a column that is packed with a stationary phase composed of irregularly or spherically shaped particles. In HPLC, the asphaltene fraction needs to be removed before proceeding with the chromatography (Fan et. al, 2002).

3. Medium-pressure liquid chromatography (MPLC): MPLC uses a pre column containing thermally-deactivated silica and a main column of activated silica as the stationary phase with n-hexane serving as the mobile phase. This technique separates oils and extracts into saturate and aromatic fractions for subsequent biomarker analysis through gas chromatography. Weatherford believed that MPLC distribution of compounds is more representative of the produced hydrocarbon fluids.

Table 4.2 summarizes the results of four Bakken unpressurized well head oil samples. Conventional SARA analysis was used in the first two samples while other samples were analyzed by the MPLC method. It is observed that Bakken crude oil is more paraffinic due to a higher composition of saturates than aromatics.

<table>
<thead>
<tr>
<th>Method</th>
<th>Field</th>
<th>Sample #</th>
<th>Saturates</th>
<th>Aromatics</th>
<th>Resins</th>
<th>Asphaltene</th>
<th>Saturates/Aromatic</th>
<th>Asphaltene/Resin</th>
</tr>
</thead>
<tbody>
<tr>
<td>SARA</td>
<td>Bailey</td>
<td>1</td>
<td>51.69</td>
<td>40.90</td>
<td>7.35</td>
<td>0.06</td>
<td>1.3</td>
<td>0.01</td>
</tr>
<tr>
<td>SARA</td>
<td>Reunion</td>
<td>2</td>
<td>46.55</td>
<td>46.55</td>
<td>6.55</td>
<td>0.35</td>
<td>1.0</td>
<td>0.05</td>
</tr>
<tr>
<td>MPLC</td>
<td>Reunion</td>
<td>3</td>
<td>49.83</td>
<td>28.09</td>
<td>8.03</td>
<td>0.33</td>
<td>1.8</td>
<td>0.04</td>
</tr>
<tr>
<td>MPLC</td>
<td>Reunion</td>
<td>4</td>
<td>41.76</td>
<td>27.24</td>
<td>8.24</td>
<td>6.09</td>
<td>1.5</td>
<td>0.74</td>
</tr>
</tbody>
</table>

Table 4.2: SARA and MPLC analyses results in weight percent
The ratio of saturates to aromatics and asphaltenes to resins were computed and used to determine the stability of the oil (Stankiewicz, 2002). The samples from Reunion have a higher saturate/aromatic ratio and lower weight percent of saturates. Figure 4.9 shows that the Middle Bakken reservoir crude oils’ saturate/aromatic ratio lies within the stable region, but in some cases close to the stability boundary. This indicates that during natural production wells are not likely to have asphaltene precipitation issues. This information is not only crucial in the primary depletion but also in the consideration of CO₂ injection. Once CO₂ and crude oil mix in the reservoir, asphaltene flocculation can occur (Novasad and Costain, 1990; Zadeh et. al, 2011)

![Figure 4.9: Saturate/aromatic vs. asphaltene/resin plot (Modified from Stankiewicz, 2002).]

4.1.4 Total Acid Number, Total Base Number, and Water Content of Oil

Acid number and water content of the crude give information about the potential for corrosion problems and other operational issues.

Total acid number (TAN) is determined by the amount of potassium hydroxide in milligrams that is needed to neutralize the acids in one gram of oil [ASTM-D664 (ASTM, 1983)]. Total base number (TBN) is determined by measuring the amount of potassium hydroxide in milligrams taken to neutralize the base reserve in one gram of oil [ASTM-D2896 (ASTM, 2011)]. The water in crude oil is measured by potentiometric Karl Fischer titration [ASTM-D 4377 (ASTM, 2011)].

Acid number measurements attempt to characterize oil with respect to concentration of strong and weak acids (Fan and Buckley, 2006). Table 4.3 illustrates the measurements of Bakken oil samples for the total acid number, the total base number, and the water content. Low-TAN is expected based on the SARA results. Because large molecules mostly present in the resin and asphaltene fraction represents the
acids in crude. The basic groups (TBN) are also located in the heavy end fraction of the crude. This information is also important when discussing adsorption of bases and acids from crude oil onto reservoir clay minerals in Chapter 5. The water content is also low which indicates the lower risk of corrosion.

Table 4.3: Summary of available Bakken crude oil properties

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Method</th>
<th>Bailey</th>
<th>Reunion Bay</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Acid (mg KOH/g)</td>
<td>ASTM D664</td>
<td>0.09</td>
<td>Not detected</td>
</tr>
<tr>
<td>Total Base (mg KOH/g)</td>
<td>ASTM D2896</td>
<td>Not measured</td>
<td>1.16</td>
</tr>
<tr>
<td>Water Content (wt %)</td>
<td>ASTM D 4377</td>
<td>0.01</td>
<td>0.02</td>
</tr>
</tbody>
</table>

4.2 Produced Reservoir Water Properties

In this section, the high salinity composition of the reservoir water is presented. The fluid-rock interaction with the existence of high-salinity reservoir water during low salinity water injection will be discussed in Chapter 5.

Water salinity is a dissolved salt and mineralogy of formation water. Ionic concentration of each dissolved salt is used to calculate equivalent NaCl concentration. First, the weighting multipliers, M, for various ions are determined from Fig. 4.10.

![Figure 4.10: Multipliers for converting ionic concentrations of dissolved salts to NaCl concentration equivalents (Courtesy of Schlumberger).](image)
Then, the concentration of each ion, $C_{si}$, is multiplied by its weighting factor. The equivalent NaCl concentration, $C_{sp}$, is obtained by adding the products for all ions (Eq. 4.3) (Tiab and Donaldson, 2012).

$$C_{sp} = \sum_{i=1}^{n} M_i C_{si}$$

[4.3]

Using the calculated NaCl equivalent concentration, resistivity of formation water at 75°F, $R_{w75}$ can be obtained using the following equation:

$$R_{w75} = \frac{1}{2.74 \times 10^{-4} C_{sp}^{0.995} + 0.0123}$$

[4.4]

The resistivity of formation water is calculated at the reservoir temperature of Bakken, 240°F, using Arps’ equation:

$$R_{wT_2} = R_{wT_1} \left( \frac{T_1 + 6.77}{T_2 + 6.77} \right)$$

[4.5]

Table 4.4 shows an example of water analysis from a well in Bailey. The described procedure was used to calculate the equivalent NaCl concentration and the formation water resistivity at reservoir temperature.

**Table 4.4** Results of water analysis in Bailey field, North Dakota Bakken

<table>
<thead>
<tr>
<th>Ions</th>
<th>$C_{si}$ (mg/l)</th>
<th>Multiplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>Na</td>
<td>96100.0</td>
<td>1</td>
</tr>
<tr>
<td>Ca</td>
<td>21112.8</td>
<td>0.8</td>
</tr>
<tr>
<td>Mg</td>
<td>1049.4</td>
<td>1.55</td>
</tr>
<tr>
<td>K</td>
<td>4580.0</td>
<td>0.9</td>
</tr>
<tr>
<td>Br</td>
<td>19.2</td>
<td>0.44</td>
</tr>
<tr>
<td>Cl</td>
<td>187918.0</td>
<td>1</td>
</tr>
<tr>
<td>HCO$_3$</td>
<td>18.3</td>
<td>0.35</td>
</tr>
<tr>
<td>SO$_4$</td>
<td>603.5</td>
<td>0.7</td>
</tr>
</tbody>
</table>

**Water Analysis Results**

| Equivalent NaCl Concentration, ppm | 307,094 |
| Water Resistivity (75 °F), Ωm        | 0.033   |
| Water Resistivity (240 °F), Ωm       | 0.032   |
Total dissolved solids (TDS) of four additional water samples were also measured in various Bakken fields. These samples were taken from wells that have been producing for a long time. The objective was to eliminate the low-salinity fracturing fluid effect in the collected water sample and therefore be more of true formation. Table 4.5 summarizes the results of the water measurement in terms of pressure, temperature, pH and specific gravity for three Middle Bakken samples and one Three Forks sample collected in various fields. Summary of the test results, shown in Table 4.6, shows that average TDS for Bakken reservoir water is very saline, averaging 285,000 mg/L. In contrast, the fracturing fluid used during the stimulation is very low saline water with TDS less than 5000 mg/L.

<table>
<thead>
<tr>
<th>Field Name</th>
<th>Sample #</th>
<th>Formation</th>
<th>Temperature (°C)</th>
<th>Pressure (psi)</th>
<th>Measured pH</th>
<th>Specific Gravity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reunion Bay</td>
<td>1</td>
<td>Middle Bakken</td>
<td>71</td>
<td>71</td>
<td>5.8</td>
<td>1.202</td>
</tr>
<tr>
<td>Murphy Creek</td>
<td>2</td>
<td>Middle Bakken</td>
<td>76</td>
<td>45</td>
<td>5.6</td>
<td>1.187</td>
</tr>
<tr>
<td>Bailey</td>
<td>3</td>
<td>Middle Bakken</td>
<td>88</td>
<td>40</td>
<td>5.8</td>
<td>1.202</td>
</tr>
<tr>
<td>Bailey</td>
<td>4</td>
<td>Three Forks</td>
<td>88</td>
<td>44</td>
<td>5.6</td>
<td>1.204</td>
</tr>
</tbody>
</table>

Table 4.5: Bakken formation water samples

<table>
<thead>
<tr>
<th>Field Name</th>
<th>Sample #</th>
<th>Chloride (mg/L)</th>
<th>Sulfate (mg/L)</th>
<th>Bicarbonate (mg/L)</th>
<th>Sodium (mg/L)</th>
<th>Calcium (mg/L)</th>
<th>Magnesium (mg/L)</th>
<th>Iron (mg/L)</th>
<th>Barium (mg/L)</th>
<th>Strontium (mg/L)</th>
<th>TDS (mg/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reunion Bay</td>
<td>1</td>
<td>172500</td>
<td>223</td>
<td>122</td>
<td>85739</td>
<td>19790</td>
<td>1253</td>
<td>333</td>
<td>23</td>
<td>1458</td>
<td>281,448</td>
</tr>
<tr>
<td>Murphy Creek</td>
<td>2</td>
<td>169500</td>
<td>291</td>
<td>37</td>
<td>87277</td>
<td>16750</td>
<td>1468</td>
<td>30</td>
<td>10</td>
<td>1200</td>
<td>276,569</td>
</tr>
<tr>
<td>Bailey</td>
<td>3</td>
<td>182200</td>
<td>270</td>
<td>110</td>
<td>84966</td>
<td>24980</td>
<td>1753</td>
<td>241</td>
<td>16</td>
<td>1921</td>
<td>296,463</td>
</tr>
<tr>
<td>Bailey</td>
<td>4</td>
<td>183400</td>
<td>260</td>
<td>122</td>
<td>95138</td>
<td>17870</td>
<td>1268</td>
<td>210</td>
<td>18</td>
<td>1377</td>
<td>299,677</td>
</tr>
</tbody>
</table>

Table 4.6: Results of Bakken formation water sample analysis

4.3 Carbon Dioxide Properties

For the evaluation of miscible CO₂ injection potential in the Bakken, understanding the interaction between CO₂ and Bakken reservoir fluid and rock is crucial. CO₂ injection, as an EOR technique, is based upon the fact that the CO₂ can be miscible in oil, reduces oil viscosity, and causes oil swelling. This section summarizes these mechanisms while determining the most suitable area for CO₂ injection in Bakken in terms of both rock and fluid properties. The experiments presented in this section used the second fluid sample from Reunion Bay listed in Table 4.1. The fluid characterization of this sample was discussed in Fig. 4.7 and Fig. 4.8. The results of the tests discussed below were integrated into the compositional simulation modeling presented in Chapter 8.
4.3.1 Minimum Miscibility Pressure (MMP)

The minimum miscibility pressure is very crucial in the evaluation and design of CO₂ injection. A rising-bubble apparatus (RBA) test by Intertek Laboratories was conducted to determine miscibility between Bakken recombined oil and CO₂ gas. The test was conducted at several pressures ranging from 2800 psi to 4300 psi so that an accurate determination of MMP could be made. A gas bubble was injected into an oil-filled visual cell at 237°F and 2800 psi as shown in Fig. 4.11. The change in shape of the rising bubble was observed until it was miscible with oil. At 3200 psi the bubble held its shape as it rose. Once it reached 3300 psi it dissolved in the oil. After this point, bubbles broke up immediately and disappeared rapidly.

![Figure 4.11: The CO₂ Gas - Recombined Oil interactions that were observed at a series of pressures at reservoir temperature.](image)

MMP estimated from the RBA experiment was used in the following studies:
- Designing laboratory experiments of steady-state permeability measurement with supercritical CO₂ and high pressure spontaneous imbibition (Chapter 5)
4.3.2 Carbon Dioxide Solubility

Solubility is a strong function of pressure, and to a lesser degree, temperature and oil composition. CO₂ is more soluble in hydrocarbons as a gas rather than a liquid phase. The solubility decreases as the bubble point pressure of crude oil increases, requiring higher CO₂ injection pressure. In the study area, Murphy Creek has the lowest bubble point pressure of 1389 psi (Table 4.1) followed by Bailey and Reunion Bay.

Carbon dioxide is soluble in water to a much lesser extent than in crude oils. The solubility of carbon dioxide in water is a function of salinity, pressure and temperature. Chang et al. (1996) developed correlations for CO₂ solubility in distilled water (Fig. 4.12) as well as for the effect of salinity on CO₂ solubility. The correlations indicate that solubility in water increases with increasing pressure and decreasing salinity. Considering average initial pressure of 7800 psi and reservoir temperature of 240°F, approximately 190 SCF of CO₂ is lost per STB of water (Fig. 4.12).

Considering an initial water saturation of 0.5 in Middle Bakken formation (Chapter 3), CO₂ loss due to solubility in water is can be significant in Bakken. However, higher solubility of CO₂ expected in oil and to a lesser extent in water can still result in a reduction in oil viscosity and a small decrease in water viscosity. This may enhance the oil mobility in the reservoir. When injecting CO₂ with a low salinity-fracturing fluid, CO₂ consumption can be increased due to low water salinity.

Figure 4.12: Calculated CO₂ solubility in distilled water by Chang et al. (1996) in comparison with the measured values by Wiebe (1941).
4.3.2 Oil Swelling and Viscosity Reduction

The volume of crude swelled when contacting with CO₂. The amount of swelling increases with increasing of CO₂ solubility. The swelling factor is defined as the volume of the oil and dissolved CO₂ at saturation pressure and system temperature, divided by the CO₂-free volume of the oil at the same temperature and bubble point pressure.

Another important impact of CO₂ on crude oil systems is CO₂ causes reduction in oil viscosity. The viscosity of oil saturated with CO₂ is a function of temperature, pressure and concentration of dissolved CO₂.

Swelling and viscosity measurements were performed by Intertek Laboratories for the Bakken recombined fluid Sample #2 in Reunion Bay. The PVT cell experiments were conducted at reservoir temperature. CME was performed after each addition of CO₂.

**Table 4.7** displays a summary of the measured data: the mole percent gas added, the saturation pressure, density and viscosity of the single-phase fluid at saturation pressure, the fluid formation volume factor, the solution GOR, and the swelling factor. The solution GOR in **Table 4.7** represents the swelling gas-oil ratio that is the cumulative volume of CO₂ at standard conditions per initial oil volume. For example, 20.96% molar of CO₂ injection swells the oil by 11%, decreases oil viscosity by 67%, and increases bubble point pressure from 2530 psi to 2782 psi, oil density by 1.2%, and formation volume factor by 14%.

**Table 4.7**: Summary of Bakken swelling tests at 237°F with CO₂

<table>
<thead>
<tr>
<th>Solvent mole %</th>
<th>Bubble Point Pressure psia</th>
<th>Density g/cc</th>
<th>Viscosity cp</th>
<th>Formation Volume Factor bbl₂P°F/bbl₆₀°F</th>
<th>Solution Gas-Oil Ratio scf/stb</th>
<th>Swelling Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.00</td>
<td>2530</td>
<td>0.647</td>
<td>0.383</td>
<td>1.615</td>
<td>867.34</td>
<td>1.000</td>
</tr>
<tr>
<td>13.09</td>
<td>2663</td>
<td>0.652</td>
<td>0.305</td>
<td>1.736</td>
<td>1091.35</td>
<td>1.068</td>
</tr>
<tr>
<td>20.96</td>
<td>2782</td>
<td>0.655</td>
<td>0.257</td>
<td>1.845</td>
<td>1342.56</td>
<td>1.110</td>
</tr>
<tr>
<td>45.20</td>
<td>3403</td>
<td>0.669</td>
<td>0.153</td>
<td>2.271</td>
<td>2198.93</td>
<td>1.326</td>
</tr>
<tr>
<td>54.60</td>
<td>3703</td>
<td>0.676</td>
<td>0.128</td>
<td>2.674</td>
<td>2904.42</td>
<td>1.463</td>
</tr>
</tbody>
</table>

The EOS regression against the laboratory measured swelling data was performed using PVTsim (Calsep, 2011). The original fluid (i.e. 0% solvent) and four injection volumes of CO₂, listed in **Table 4.7**, were characterized to the same pseudo-components. The lumping was done using five-component EOS to include N₂-C₁, CO₂, C₂-C₃, C₄-C₆, and C₇⁺. The regression continued until a good agreement between the experimental and calculated data was obtained while complying with monotonical trend of critical temperature, critical pressure, and acentric factor for C₇⁺ components. For illustration, CCE, DL,
viscosity, and swelling test are shown in Fig. 4.13 and Fig. 4.14. The plots include the lab measurement (blue), EOS predictions before regression (orange), and after regression (green). It can be seen the EOS predicted values reasonably matched with the lab data.

**Figure 4.13:** Bakken sample with lab measurement (blue), EOS predictions before regression (orange) and after regression (green) to CCE, DL, and viscosity.
4.3.2 Chemical Reaction with Rock

CO₂ can also influence rock properties. CO₂ can react with water to form carbonic acid as shown in the equilibrium relationship:

\[ \text{CO}_2 + \text{H}_2\text{O} \rightarrow \text{H}_2\text{CO}_3 \]  \[4.6\]

Because H₂CO₃ results in a reduction of pH, swelling and blockage of the vertical communication through shale rocks such as Upper Bakken and Lower Bakken shale should be prevented. When CO₂ reacts with calcareous rocks (e.g., low porosity and permeability rock from Middle Bakken with a high calcite content), it may improve injectivity because the rock can be dissolved by H₂CO₃ due to the following reactions:

\[ \text{H}_2\text{CO}_3 + \text{CaCO}_3 \rightarrow \text{Ca} (\text{HCO}_3)_2 \]  \[4.7\]

\[ \text{H}_2\text{CO}_3 + \text{MgCO}_3 \rightarrow \text{Mg} (\text{HCO}_3)_2 \]  \[4.8\]
The bicarbonates thus formed are quite soluble in water. This effect may contribute to an increase in the permeability sections where carbonates are dominant in the mineralogy. Both reduction in oil viscosity and increase in reservoir permeability due to CO₂ injection can improve pressure diffusivity in convection flow.
CHAPTER 5

RESERVOIR ROCK PROPERTIES

This chapter describes rock properties of Middle Bakken formation. The sample preparation, matrix properties, and fracture properties are presented. A permeability measurement applicable for tight rocks is discussed and compared against the existing methods. The measurement of relative permeability, stress dependent permeability, and porosity are presented. To further characterize the target drilling zone in Middle Bakken, the petrographic analyses, including X-ray diffraction (XRD), computed tomography (CT) scan images of core plugs, and thin section petrology, were integrated in this study. The morphology of the rock samples were also observed using argon ion-milled scanning electron microscopy (AIM-SEM).

The static core characterization was used to understand the flow mechanism via corefloods. The study was to investigate the use of supercritical CO₂ in permeability measurements, the success of low salinity frac fluid stimulation, and the potential application of low salinity waterflood. This requires an integrated approach to relate rock properties with fluid properties such as formation brine composition, oil chemistry, and CO₂ properties (Chapter 4).

This chapter includes the following sections: (1) sample preparation, (2) matrix properties, (3) fracture properties, and (4) imbibition tests.

5.1 Sample Preparation

Two vertical wax-preserved cores were obtained from the laminated facies of Middle Bakken in Bailey. One-inch diameter and four-inch long horizontal core plugs (parallel to bedding planes) were obtained for the coreflood and imbibition tests. Four-inch long core plugs were then trimmed to two-inch, one-inch, and half-inch long for the steady-state permeability and imbibition tests. The end trim pieces of those samples were used for XRD, SEM, and thin section analyses. The cores were selected using the microscopic pictures and CT scan images to identify layering system and micro-fractures. Figures 5.1 and 5.2 show the locations where the four-inch long core plugs were taken with their thin sections. The explanations of thin sections and XRD results will be discussed in the later sections of this chapter.

From the core section #1 (Fig. 5.1), three plugs (red, blue, and orange) were used for the imbibition tests. One of core plugs was used for the permeability measurement (green) and an adjacent core from the same depth was used for the fluid droplet test (green).

From the core section #2 (Fig. 5.2), one plug was used for the imbibition test and an adjacent core from the same depth was used for the multi-stress dependent permeability test.
Several Middle Bakken core plugs from Reunion Bay were used in the coreflood and imbibition tests. Similarly, these samples were characterized with XRD, SEM, and thin section. This rock type has a higher dolomite than the cores taken from the Bailey well.
5.2 Matrix Properties

A series of petrographic analyses and permeability measurements were performed for Middle Bakken formation to characterize flow capacity, mineralogy, and morphology of matrix rocks.

5.2.1 Matrix Mineralogy

In evaluating mineralogical and textural characterization, thin section was used to observe the sample framework, porosity, and grain size. Besides thin section, XRD analysis was used to characterize mineralogy, clay type, and clay abundance. XRD records the diffraction of X-rays by solids. The unique arrangement of atoms in each mineral’s crystal structure interacts with the X-ray beam. The mineral analysis from XRD, was provided by Ellington’s D4 Endeavor with LynxEye Detector.

Based on thin sections, the core section #1 (Fig. 5.1) was characterized as clay-rich laminations alternating with higher volume of quartz, feldspar and calcite. The core section #2 (Fig. 5.2) had a high calcite volume with pyrite-rich laminations.

From the XRD analyses, the mineralogy of the core section #1 indicates that quartz is the dominant mineral (average 50%) with calcite accounted for around 9%, and clays about 10%. In the core section #2, more calcite content (average 31%) with less amounts of quartz (36%) and clays (8%) were observed than those of the first core. Table 5.1 summarizes XRD results for the sample-depths shown in Fig. 5.1 and Fig. 5.2.

Table 5.1: Summary of XRD results for the core section #1 and the core section #2

<table>
<thead>
<tr>
<th>Mineralogy</th>
<th>Bailey Core Sample #1</th>
<th>Bailey Core Sample #2</th>
<th>Reunion Bay Sample</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>10847.55</td>
<td>10847.65</td>
<td>10847.75</td>
</tr>
<tr>
<td>Clays</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Smectite</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Chlorite</td>
<td>1.5</td>
<td>0.9</td>
<td>0.7</td>
</tr>
<tr>
<td>Kaolinite</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>I伊利te/Mica</td>
<td>1.14</td>
<td>0.89</td>
<td>0.89</td>
</tr>
<tr>
<td>Mx IS</td>
<td>3.6</td>
<td>0.7</td>
<td>1.6</td>
</tr>
<tr>
<td>Carbonates</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Calcite</td>
<td>9.5</td>
<td>8.9</td>
<td>9.7</td>
</tr>
<tr>
<td>Fe-Dol</td>
<td>7.1</td>
<td>9.6</td>
<td>11.3</td>
</tr>
<tr>
<td>Dolomite</td>
<td>6.4</td>
<td>4.3</td>
<td>3.9</td>
</tr>
<tr>
<td>Siderite</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Other Minerals</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Quartz</td>
<td>45.2</td>
<td>52.1</td>
<td>50.7</td>
</tr>
<tr>
<td>K-Feldspar</td>
<td>6.6</td>
<td>7.3</td>
<td>9.2</td>
</tr>
<tr>
<td>Plagioclase</td>
<td>4.2</td>
<td>5.7</td>
<td>5.1</td>
</tr>
<tr>
<td>Pyrite</td>
<td>1.3</td>
<td>0.6</td>
<td>0.5</td>
</tr>
<tr>
<td>Zeolite</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Barite</td>
<td>0.5</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Others</td>
<td>0.9</td>
<td>0.9</td>
<td>1.3</td>
</tr>
<tr>
<td>Total</td>
<td>18.4</td>
<td>10.5</td>
<td>8.4</td>
</tr>
<tr>
<td>Clays</td>
<td>23</td>
<td>22.8</td>
<td>24.9</td>
</tr>
<tr>
<td>Carbonates</td>
<td>58.6</td>
<td>66.7</td>
<td>68.8</td>
</tr>
</tbody>
</table>

5.2.2 Rock Wettability

Understanding of rock wettability is crucial task in studying oil recovery. The oil versus-water wetting preference influences many aspects of reservoir performance, particularly in water flooding and
enhanced oil recovery application. With the motivation of understanding the wettability in the research area, a fluid droplet experiment was conducted.

Fluid droplet experiment was a simple qualitative test to observe the oil spreading behavior. Major factors that can affect these results are crude, brine and surface chemistry, and surface roughness. Because the cores were sealed in wax, the exposure to air (oxidation) was minimized to retain the same fluid saturations as they were collected on the surface. The experiments were conducted under the controlled-atmosphere conditions in a glove-box apparatus (Fig. 5.3). The apparatus was evacuated with argon to minimize oxygen content to less than a half percent. This is because low oxygen level improves the wetting force and wetting time.

![Figure 5.3: Glove box used for wettability experiment (Marathon Technical Laboratory).](image)

The experiment was performed by putting 2-3 drops on three Middle Bakken core pieces. These drops are Bakken dead crude, formation brine, 5% dilute formation (low salinity), and Alka Seltzer with pH=9.2 (Fig.5.4). The test objectives include observing the wetting characteristic with formation brine, testing whether low salinity water can alter wettability, and investigating whether high pH brine can trigger nature surfactant from oil to alter wettability. It can be seen each core adsorbed oil droplet instantly upon contacting them with core, whereas there are no or limited imbibition occurred for other type of droplets. This test indicates the Middle Bakken is preferentially oil-wet. The test with limited imbibition also suggests that low salinity and high pH brines are unable to alter core from oil-wet to water-wet.
Figure 5.4: Fluid drop test #1 showing the droplets of dead oil, formation brine, 5% dilute formation, and Alka Seltzer with a ph=9.2 (from top to bottom).

5.2.3 Matrix Porosity

The matrix porosity of gas-filled pores in the selected core plugs was obtained using Boyle’s law as a gas transfer technique that involves the expansion of gas from the pores of the core. The sample was placed in a holder that has no void space around the periphery of the core. Dead volume in the system was measured by substituting a solid metal plug for the core plug. The sample was then inserted. It is essential that the end stems butt closely against the sample faces. If not, a dead volume not measured with the metal plug is created, which can yield an erroneously high pore space. Either pore volume or grain volume may be determined. This is a fairly rapid, non-destructive method, and it yields cores that can be used for further testing. At the end of the test, for each sample, the initial weight, length, diameter, grain volume, and gas filled pore volume were obtained. Using these parameters the mechanical bulk volume was calculated as follows:

\[
V_b = \left( \pi r^2 / 4 \right) L 
\]  

[5.1]

And knowing the gas-filled volume, the apparent gas-filled unstressed porosity was calculated using Eq. 5.2:

\[
\varphi = \frac{100 V_{gas}}{V_b} 
\]  

[5.2]
To confirm the caliper measurements, Archimedes bulk and grain volume using mercury were also determined. Finally, the apparent grain density was calculated using Eq. 5.3:

\[ \rho = \frac{m}{V_g} \]  \[ 5.3 \]

Where \( m \) is the initial weight, and \( V_g \) is the grain volume.

**Table 5.2** summarizes the weight, volume, and porosity of the representative plugs covering the depths for both core sections (**Fig. 5.1** and **Fig. 5.2**). The properties were measured through caliper and Boyle’s Law technique following the procedure explained above.

<table>
<thead>
<tr>
<th>Field</th>
<th>Core #</th>
<th>Depth</th>
<th>Length</th>
<th>Diameter</th>
<th>Initial Weight</th>
<th>Bulk Volume</th>
<th>Bulk Density</th>
<th>Grain Volume</th>
<th>Gas Filled Pore Volume</th>
<th>Apparent Gas Filled Unstressed Porosity</th>
<th>Apparent Grain Density</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bailey</td>
<td>1</td>
<td>10847.55</td>
<td>1.44</td>
<td>2.53</td>
<td>18.67</td>
<td>7.27</td>
<td>2.57</td>
<td>6.96</td>
<td>0.32</td>
<td>4.35</td>
<td>2.68</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>10847.65</td>
<td>5.14</td>
<td>2.54</td>
<td>66.42</td>
<td>25.79</td>
<td>2.58</td>
<td>24.98</td>
<td>0.81</td>
<td>3.13</td>
<td>2.66</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>10847.85</td>
<td>5.03</td>
<td>2.53</td>
<td>65.22</td>
<td>25.28</td>
<td>2.58</td>
<td>24.57</td>
<td>0.72</td>
<td>2.84</td>
<td>2.66</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>10850.45</td>
<td>1.37</td>
<td>2.56</td>
<td>18.39</td>
<td>6.91</td>
<td>2.66</td>
<td>6.81</td>
<td>0.10</td>
<td>1.44</td>
<td>2.70</td>
</tr>
<tr>
<td>Reunion Bay</td>
<td>5</td>
<td>10591.05</td>
<td>2.09</td>
<td>2.54</td>
<td>26.54</td>
<td>10.62</td>
<td>2.50</td>
<td>10.08</td>
<td>0.54</td>
<td>5.09</td>
<td>2.63</td>
</tr>
</tbody>
</table>

To investigate the pore structure, distribution and the hydrocarbon storage, AIM-SEM imaging was used. This analysis helped to identify compositional and textural differences for the evaluation of the pore distribution for different rock types in Middle Bakken. A polished surface of the sample was prepared by argon-ion milling and imaged with backscattered electrons. The samples do not have to have a conductive coating that can obscure the fine details of the sample surface. This provides the ability to investigate the small-scale textural features of the shale and to be able to characterize the organic particles and distribution of micro porosity.

**5.2.4 Matrix Permeability**

The matrix permeability of unconventional shale oil reservoirs is a key parameter that provides an understanding of the global flow hierarchy in the pore network and flow channels. The flow hierarchy was conceived by comparing measured permeability from cores with mini-DST, mini-frac and long pressure buildup tests (**Chapter 6**). All permeabilities derived from field tests are several orders of magnitude greater than permeability measured on core plugs. This contrast is the basis for hypothesizing
that the reservoir flow path begins with the nanometer scale matrix pores and is connected to a network of interconnected micro-fractures and macro-fractures in the stimulated reservoir volume. Therefore, it is essential to quantify the matrix-fracture flow map and deliverability in unconventional reservoirs.

**Previous Approaches**

The main challenge in unconventional core analyses is the nature of ultra-low permeability samples with nanometer pore network. The application of conventional routine core analyses methods to shales are highly questionable because of difficulties in determination of in-situ phase saturation, fluid extraction, re-saturation of the preserved samples, and aging of core to restore nature wettability. Also, conducting experiments under net confining stress requires tedious procedures. Previous industry practice of measuring permeability for shale was using crushed rock samples, also known as GRI technique (Luffel et al., 1993). However, this method has a number of short comings such as the absence of reservoir effective stress, the potential creation cracks in the crushed samples, and the lack of Klinkenberg correction, which all result in inconsistent permeability values reported by different laboratories (Tinni et al., 2012). On the other hand, plug-based permeability measurements can overcome many of the shortcomings associated with the GRI method such as pressure-decay transient technique (Brace et al., 1968) and pressure transmission technique (Metwally and Sondergeld, 2011). In both methods, permeability is determined as a measurement of the rate of fluid flow through a porous material under a pressure gradient (Darcy’s law).

\[
k = \frac{q\mu}{A} \left( \frac{dp}{dx} \right)^{-1}
\]

[5.4]

In Brace’s pulse decay experiment, the assembled sample was placed in the pressure vessel where the external pressure applied and held constant. Both upstream and downstream pressure was initially equal. At time zero, upstream pressure \( P_u \) was increased by \( \Delta p \) by adjusting an external valve. The pressures of upstream, \( P_u \) and downstream \( P_d \), changes are shown in Fig. 5.5. After some time both pressure approached a constant common value \( P_f \). The decay characteristics depend on the permeability, the dimensions of the sample and reservoirs, and physical characteristics of the fluid. The pressure decay imposed at the upstream end of the sample is measured with the following equation:

\[
(P_u - P_f) = \Delta P \left[ \frac{V_d}{V_u} + \frac{V_d}{V_u} \right] e^{-mt}
\]

[5.5]
Where the slope from a semi-log plot of pressure decay against time (Fig. 5.5), \( m \) is given by Eq. 5.6,

\[
m = \left( \frac{kA}{\mu c_f L} \right) \left( \frac{1}{V_u} + \frac{1}{V_d} \right)
\]  \[5.6\]

Where \( c_f \) is the fluid compressibility, \( k \) is the permeability, \( \mu \) is the viscosity, \( L \) is the length of the sample, and \( A \) is the area of the sample. \( V_u \) and \( V_d \) represent the volume for the upstream and downstream reservoir, respectively. And permeability is determined from the slope of the logarithm of differential pressure between upstream and final point against time.

\[
k = \left( \frac{m \mu c_f L}{A} \right) \left( \frac{V_d + V_u}{V_u V_d} \right)
\]  \[5.7\]

**Figure 5.5:** Pressure determination from pulse decay technique.

In pressure transmission technique by Metwally and Sondergeld (2011), the pressure build-up response is measured in the downstream reservoir connected to the core plug while applying constant pressure at the upstream (Fig. 5.6). That implies that the initial pressure difference decays only after the pressure change is sensed at the downstream of the sample. This method provides more reliable result since the downstream pressure build up is a response across the entire core plug.
Figure 5.6: Pressure determination from pressure buildup technique.

Equation 5.8 is the analytical equation for the dimensionless pressure difference between the two reservoirs as a function of time, referenced from Hsieh et al. (1981):

\[
\dot{p}(t) = \frac{2 \gamma \theta \dot{p} \left( \gamma^2 + \theta \right)^{\frac{1}{2}}}{\theta^4 + \theta^2 \left( \gamma + \gamma^2 \right)} \exp \left( -\frac{\theta^2 kt}{c_f \phi \mu L^2} \right) \]  

[5.8]

Where \( \theta \) is the root of the equation, \( \gamma \) is the ratio of the sample pore volume to the downstream reservoir volume, \( V_d \), \( \phi \) is the porosity of the sample, \( L \) is the length, \( c_f \) is static compressibility of the fluid, and \( \mu \) is the viscosity. Then, taking the natural log of Eq. 5.8, the permeability can be easily determined from the slope of this equation:

\[
\dot{p}(t) = \ln \left[ \frac{2 \gamma \theta \dot{p} \left( \gamma^2 + \theta \right)^{\frac{1}{2}}}{\theta^4 + \theta^2 \left( \gamma + \gamma^2 \right)} \right] - \left( -\frac{\theta^2 k}{c_f \phi \mu L^2} \right) t
\]  

[5.9]

Where the slope, \( m \) is given by Eq. 5.10,

\[
m = -\frac{\theta^2 k}{c_f \phi \mu L^2}
\]  

[5.10]

And permeability is determined from the slope of the logarithm of differential pressure between upstream and downstream point against time.
In general, it is not practical to determine the permeability of ultra-tight rocks using steady-state methods. However, it is the most reliable method of all others mentioned above since it depends on measuring the flow rate or velocity of fluid through the sample if a constant pressure drop is applied, rather than measuring pressure-decay or pressure build-up response at one end of the sample. Our proposed method reduces the test time and makes permeability measurements of ultra-low permeability samples possible and reliable by using a steady-state method. The following section discusses this type of measurement using kerosene and supercritical CO₂. The methodology and example of each method are presented to contrast their pros and cons.

Proposed Approach

1. Steady-State Permeability Measurement with Kerosene

Kerosene was used as an injection fluid for the steady-state measurement to measure effective liquid permeability. Under steady-state conditions, Darcy’s law for liquid (Eq. 5.12) was used to calculate permeability by knowing measured flow rate, fluid viscosity, surface area, and pressure drop across the length of the sample.

\[ k_{\text{liquid}} = \frac{q \mu L}{A \Delta p} \]  

[5.12]

Where \( q \) (cc/s) is the flow rate, \( k_{\text{liquid}} \) (md) is the permeability, \( A \) is the cross-section area (cm²), \( \Delta p \) (atm) is the pressure differential across the sample length, \( L \) (cm), and \( \mu \) (cp) is the fluid viscosity.

The test was conducted at 30° C and at 500 psi net effective stress (confining stress of 1000 psi). Figure 5.7 depicts the end of a several month long effort to resaturate a preserved native state sample and measure end point permeability to oil at \( S_{wi} \) (approximately 50%). The gas in the sample occurred as a result of blow-down during depressurization from reservoir to surface. It was assumed that the gas volume was originally filled with oil in the reservoir.

The main challenge in conducting this type of test was to displace gas with oil without moving water. In order to accomplish this, the sample was first flowed with kerosene, assumed to be compatible with oil, under large back pressure. This decreased the gas bubble to a small size and swept it out of the
core. Kerosene was flowed long enough until steady-state behavior was obtained for a sufficiently long period. The steady-state behavior was sustained for 18 days shown in the second plot of Fig. 5.7.

**Figure 5.7:** Steady-state effective liquid permeability measurement using kerosene.

Darcy equation for liquid, given in Eq. 5.12, was used to calculate effective liquid permeability which yielded an end point permeability of approximately 2.7E-05 md. Sample and test details are summarized in Table 5.3.

**Table 5.3:** Details of steady state matrix-permeability measurement using kerosene

<table>
<thead>
<tr>
<th>Sample and Test Details</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation</td>
<td>Middle Bakken</td>
</tr>
<tr>
<td>Length (cm)</td>
<td>2.53</td>
</tr>
<tr>
<td>Diameter (cm)</td>
<td>2.52</td>
</tr>
<tr>
<td>Area (cm²)</td>
<td>4.99</td>
</tr>
<tr>
<td>Injection Rate (cc/hr)</td>
<td>0.00308</td>
</tr>
<tr>
<td>Kerosene Viscosity (cp)</td>
<td>0.8</td>
</tr>
<tr>
<td>Bulk Volume (cc)</td>
<td>12.87</td>
</tr>
<tr>
<td>Bulk Density (g/cc)</td>
<td>2.57</td>
</tr>
<tr>
<td>Pore Pressure (psi)</td>
<td>500</td>
</tr>
<tr>
<td>Effective Stress (psi)</td>
<td>500</td>
</tr>
<tr>
<td>Temperature (°C)</td>
<td>30</td>
</tr>
<tr>
<td>Permeability (md)</td>
<td>2.7E-05</td>
</tr>
</tbody>
</table>

2. **Steady-State Permeability Measurement with Supercritical Carbon Dioxide**

Due to the ultra-low permeability of the core plug, achieving steady-state conditions with kerosene can last months for only a single point of effective oil permeability. Because of this tedious and time-consuming test, the use of supercritical CO₂ was investigated. Supercritical CO₂ is miscible with residual liquids. This eliminates standard core extraction and re-saturation procedures in conventional
methods. Low viscosity of supercritical CO$_2$, approximately 0.07 cp, enables measuring flow rate and pressure gradients while its low compressibility enables reaching steady state in a short time.

Another concern in matrix permeability measurements on ultra-low permeability core plugs is the deviation from the Darcy flow regime which becomes important when the pores are extremely small and measurements are conducted at low pressures. From the kinetic theory of gases, there is an average distance that the gas molecules would travel before colliding with one another. This is called as the mean free path, $\lambda$, and computed using the following equation:

$$\lambda = \frac{k_B T}{\sqrt{2\sigma^2 P}}$$

Where $k_B$ is the Boltzmann constant in J/K, $T$ is the absolute temperature in K, $\sigma$ is the collision diameter for the used gas type in meters, and $P$ is the average pore pressure in Pascals. The collision diameter for the most commonly used gases, helium and methane with carbon dioxide is given in Table 5.4. The higher collision diameter of carbon dioxide in a high pore pressure system results in a smaller mean free path than those of helium at low pore pressure as used in the case of crushed sample measurements (Cui et al., 2009).

<table>
<thead>
<tr>
<th>Gas Type</th>
<th>Collision Diameter, $\sigma$ (nm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO$_2$</td>
<td>0.407</td>
</tr>
<tr>
<td>CH$_4$</td>
<td>0.382</td>
</tr>
<tr>
<td>He</td>
<td>0.256</td>
</tr>
</tbody>
</table>

Depending on the ratio of the mean free path of the gas molecules to the average pore radius (Eq. 5.14), Knudsen number $K_n$ is calculated to identify the type of flow regime in porous media, including Darcy, slip, transition, and free molecular flow, using the following equation:

$$K_n = \frac{\lambda}{r}$$

Where $r$ is the average pore radius. In our case, the average pore throat radius of the Middle Bakken has a value of 0.02 microns (20 nm), which was reported in Ramakrishna et al.’s study (2010).
using mercury injection. When $K_n \leq 0.001$, flow can be classified as Darcy flow and when it is $0.001 \leq K_n \leq 0.1$, slip flow can exist in porous media. For large pore sizes and at high pressures, the flow in a core plug can be completely described by Darcy’s flow equation. If the flow exhibits slip flow regime, Darcy’s law is still applicable with Klinkenberg correction (Klinkenberg, 1941) using Eq. 5.15:

$$k_g = k_\infty \left(1 + \frac{b_k}{P_m}\right)$$

Where $k_g$ is the apparent gas permeability measured at a mean pore pressure $P_m$, $k_\infty$ is the Klinkenberg corrected absolute permeability at infinite pore pressure, and $b_k$ is the Klinkenberg coefficient that depends on the gas and rock properties. The supercritical CO$_2$ steady-state permeability measurement was designed at 3500 psi pressure which was both higher than the critical pressure of CO$_2$ (1071.3 psi) and the minimum miscibility pressure of 3300 psi; and at 50°C temperature higher than critical temperature of CO$_2$ (31.1°C). This provided carbon dioxide to behave as a supercritical fluid and also miscible with Bakken crude oil. Because the measurements were conducted at high mean pore pressure, Klinkenberg correction was not required.

The experimental apparatus was specially designed by Rosen et al. (2013) (Fig. 5.8). The apparatus is comprised of a dual pump steady-state system with the injection pump injecting at a constant rate while the back pump maintains a constant pressure. At steady-state both pumps move at an identical rate (within experimental error) and at a constant pressure differential across the sample. The procedure was repeated at three rates to ensure linear Darcy behavior with an intercept through the origin. The sample used was an intact cylindrical plug mounted in an isostatic stress cell with a confining pressure meant to represent effective reservoir stress. For Bakken core measurements, the confining stress is around 5350 psi to represent an effective stress of 1850 psi and a pore pressure of 3500 psi.

Figure 5.8: Experimental configuration with the design equipment limits.
A sufficient pore volume was needed to flow as a repetitive test in order to ensure that the composition of what is injected is the same as what is produced. When the pressure gradient was proportional to rate, Darcy flow for gas (Eq. 5.16) was used to calculate permeability of the sample. Depending on miscibility, sweep and displacement efficiency, results may represent value somewhere in between absolute and effective permeability.

\[
k_{\text{gas}} = \frac{\mu_{\text{gas}} L}{A} \frac{z_m}{z_1} \left( \frac{2000}{p_1^2 - p_2^2} \right) q \tag{5.16}
\]

Where \( \mu_{\text{gas}} \) (cp) is the gas viscosity; \( k_{\text{gas}} \) (md) is gas the permeability compared to Eq. 5.12, and \( z \) is the compressibility factor. Subscript 1 represents inlet of the core, 2 for the outlet of the core and \( m \) stands for the mean value. Assuming ideal gas behavior, \( z \)-factor is not taken into account unless the pressure drop across the core length is high.

For illustration, the pressure and flow rate during CO\(_2\) steady-state permeability measurement was presented in Fig. 5.9. The steady-rate profiles at three different differential pressures were observed in the first plot while the second plot shows the total injected volume with the temperature profile. The time to reach steady state for single point measurement took 2.5 days in comparison with the months required to run the kerosene experiment.

![Figure 5.9: Supercritical CO\(_2\) steady-state permeability measurement.](image)

Both injection and back pressure were plotted against corresponding steady-rates to confirm the linear Darcy behavior (Fig. 5.10). This measurement yielded a matrix permeability of 0.0003 md. The sample and test details are provided in Table 5.5.
Figure 5.10: Differential pressure vs. injection flow rate and back flow rate for the steady-state matrix permeability measurement with supercritical CO₂

Table 5.5: Details of steady state matrix-permeability measurement using supercritical CO₂

<table>
<thead>
<tr>
<th>Sample and Test Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation</td>
</tr>
<tr>
<td>Length (cm)</td>
</tr>
<tr>
<td>Diameter (cm)</td>
</tr>
<tr>
<td>Area (cm²)</td>
</tr>
<tr>
<td>Injection Rate (cc/hr)</td>
</tr>
<tr>
<td>Viscosity (cp)</td>
</tr>
<tr>
<td>Bulk Volume (cc)</td>
</tr>
<tr>
<td>Bulk Density (g/cc)</td>
</tr>
<tr>
<td>Pore Pressure (psi)</td>
</tr>
<tr>
<td>Effective Stress (psi)</td>
</tr>
<tr>
<td>Temperature (°C)</td>
</tr>
<tr>
<td>Permeability (mD)</td>
</tr>
</tbody>
</table>

5.2.5 Matrix Relative Permeability

Relative permeability data for the matrix was obtained using the CoreLab laboratory results (Table 5.6) from unsteady-state water-oil relative permeability experiment. The experiment was conducted at 1600 psi of net confining stress and 70°F.

First, the clean and dry samples were pressure saturated with simulated formation brine and weighed. The samples were then desaturated while the core was embedded by air to an irreducible water saturation by centrifuge. The samples were vacuum saturated with laboratory oil. Each sample was loaded into a hydrostatic coreholder and the appropriate net confining stress applied. Permeability of oil at irreducible water saturation was measured at two injection rates. Synthetic formation brine was then injected at a constant rate, while collecting produced oil and water volumes and monitoring differential pressure and cumulative time, until a water-cut of 99.95 percent was achieved. Effective permeability to
brane at residual oil saturation was determined at two injection rates. The gas relative permeability end-point was based on a water-gas system experiment only. To obtain the gas relative permeability end-point in the three-phase gas-oil-water environment, the core saturated with irreducible brine and oil should be centrifuged against air.

**Table 5.6:** Unsteady state oil-water relative permeability results for Middle Bakken core sample

<table>
<thead>
<tr>
<th>Middle Bakken Matrix Sample</th>
</tr>
</thead>
<tbody>
<tr>
<td>Irreducible water saturation, $S_{wr}$</td>
</tr>
<tr>
<td>Irreducible oil saturation, $S_{ar}$</td>
</tr>
<tr>
<td>Absolute permeability, (md)</td>
</tr>
<tr>
<td>Porosity (--)</td>
</tr>
<tr>
<td>Gas permeability at $S_{wr}$ (md)</td>
</tr>
<tr>
<td>Oil permeability at $S_{wr}$ (md)</td>
</tr>
</tbody>
</table>

The end-point relative permeability of gas, oil, and water was calculated as illustrated in Eq. 5.17 - Eq. 5.19, respectively. Relative gas permeability at irreducible water saturation, $S_{wr}$:

$$k_{rg}^* = \frac{k_{g@S_w}}{k_a} = \frac{0.00144}{0.015} = 0.096$$

[5.17]

Relative oil permeability at irreducible water saturation, $S_{wr}$:

$$k_{ro}^* = \frac{k_{o@S_w}}{k_a} = \frac{0.00155}{0.015} = 0.103$$

[5.18]

Relative water permeability at irreducible oil saturation, $S_{or}$:

$$k_{rw}^* = \frac{k_{w@S_w}}{k_a} = \frac{0.000362}{0.015} = 0.0241$$

[5.19]

Three-phase relative permeability curves for both water-oil and liquid-gas systems were generated using Corey’s equations (Eq. 5.20 - Eq. 5.24). Residual oil saturation of 0.2 was assumed in liquid-gas system.

For water-oil system:
\[ k_{rw} = k_{rw}^* \left( \frac{S_w}{1 - S_w - S_ow} \right)^{n_w} \]  \[ 5.20 \]

\[ k_{ro} = k_{ro}^* \left( \frac{S_w}{1 - S_w - S_ow} \right)^{n_o} \]  \[ 5.21 \]

For liquid-gas system:

\[ k_{rl} = k_{ro}^* \left( \frac{S_l}{1 - S_w} \right)^{n_l} \]  \[ 5.22 \]

\[ k_{rg} = k_{ro}^* \left( \frac{1 - S_l}{1 - S_w} \right)^{n_g} \]  \[ 5.23 \]

Where \( n_i \) is the Corey exponent for each phase to control the curvature of the relative permeability curves. For the matrix relative permeability curves, we assume the followings: \( n_w=1.5, n_o=2.0, n_l=2.0, n_g=2.0. \) Figure 5.11 plots the matrix relative permeability data in water-oil and liquid-gas systems. These curves were used for the matrix region of the dual-porosity compositional model (Chapter 8). The Stone’s second three phase oil relative permeability model was included, particularly for the waterflood simulation (Stone, 1973).

**Figure 5.11:** Gas-liquid and water-oil relative permeability data for matrix.
5.2.6 Stress-Dependent Matrix Permeability

The pressure dependence of reservoir permeability and porosity can have a significant impact on well recovery. This mechanism needs to be captured while forecasting well production. There are many studies, especially for tight gas reservoirs, emphasizing the importance of stress-dependent permeability in reservoir characterization and modeling (Archer, 2008; Bachman et al, 2011). McKinney et al. (2002) shows that the hyperbolic decline often observed in tight gas reservoirs due to stress sensitivity.

To address this issue, multi-stress permeability test was conducted using three Middle Bakken matrix core samples to investigate the effect of depletion on permeability. Figure 5.12a shows the results of multi-stress laboratory tests for the two core plugs, and the corresponding matrix rock compaction curve for the simulation model (Chapter 8). The third core was used to conduct a hysteresis test. Figure 5.13b shows the matrix permeability reduction of this core and its hysteresis data point. The permeability did not recover with the restoration of the effective reservoir stress of 1850 psi.

![Figure 5.12: (a) Confining stress effect on matrix permeability and (b) hysteresis on matrix permeability. (Courtesy: Richard Rosen, MOC, 2013).](image)

5.2.7 Matrix Characterization of Middle Bakken Lithofacies-3

Because Middle Bakken Lithofacies-3 is often the drilling target for lateral Bakken wells, it was the focus of this research. As mentioned in Chapter 3, even within this lithofacies, there are two or three different zones which are marked by changes in porosity. The heterogeneity in the Lithofacies-3 was described integrating matrix permeability measurements with thin section, XRD, and SEM petrographical analyses.

1. Low Permeability and Low Porosity Middle Bakken Sample

Figure 5.13 shows the thin section and CT scan of the sample, from the depth of 10850.45 ft (Fig. 5.2). Fractures were not apparent at the scale of what was visible so it was assumed that the
measured permeability is the matrix permeability. The red box indicated on CT scan in Fig. 5.13 shows the location of the thin section sample. Thin section analysis revealed the presence of skeletal fragments and intraclasts with large mud-rimmed burrows with sand or cement fills.

Figure 5.13: CT scan and thin section of Middle Bakken low permeability sample.

Mineralogy of the sample from XRD analysis was summarized in Table 5.1 (core sample at 10850.45 ft). This indicates that calcite is the dominant mineral (approaching 52%) with quartz, iron-dolomite and dolomite accounting for up to 27% of the mineral content. Clays account for less than 10% of the mineral content. Illite accounts for a majority of the clay.

Figure 5.14 shows the ion-milled SEM of the sample which allows the characterizing of the pore system at nano-scale. Matrix permeability was expected to be extremely low in this sample due to the following observations:
- The sample consists of primarily calcite, minor quartz, and dolomite (Fig. 5.14a).
- No laminations or micro-fractures were observed at lower magnifications (Fig. 5.14a and Fig. 5.14b).
- There was minor amount of secondary intragranular porosity by the partial dissolution of feldspar grains and rock fragments. The remainder of the porosity was microporosity associated with pore-filling clays (Fig. 5.14c).
- Higher magnification images showed that calcite cemented pores were pervasive which resulted in very low porosity (Fig. 5.14c and Fig. 5.14d).
Figure 5.14: Argon ion-milled back scattered SEM analyses of Middle Bakken low permeability sample (Courtesy: Tobi Kosanke, MOC, 2013).

Figure 5.15 shows the end trim photos before and after the supercritical CO₂ injection, and test details. The permeability was calculated as 11.7 nd. Apparent gas filled unstressed porosity of the adjacent sample is 1.44% (Table 5.2).
Figure 5.15: Steady-state matrix permeability measurement of Middle Bakken low permeability sample.

2. Moderate Permeability and Moderate Porosity Middle Bakken Sample

Figure 5.16 shows the thin section and CT scan of the sample. This sample is from the depth of 10847.55 ft (Fig. 5.1). The CT scan of the sample shows no indication of fractures. Thin section analysis shows the continuous laminations characterized by high volume of clay surrounded by quartz and feldspar. The sample was described as well sorted sand-rich laminae and small scale low-angle cross laminae.

XRD analysis was summarized in Table 5.1 (core sample at 10847.55 ft). The bulk mineralogy was primarily composed of quartz (45%) followed by moderate amounts of clay, primarily illite (13.1%), and carbonates consisting of calcite (9.5%), iron-dolomite (7.1%), and dolomite (6.4%).
Figure 5.17 shows various magnifications of SEM images. Matrix permeability was expected to be higher in this sample than the low-permeability sample. The following list explains the reasons for this:

- The high volume of quartz and clays was observed (Fig. 5.17a).
- Porosity was limited to detrital clay-filled, irregularly shaped or slot-like pores (Fig. 5.17b).
- Illite and clay-sized grains are connected and surrounded by dolomite and quartz. No calcite was observed in the pores (Fig. 5.17c).
- High magnification image of a clay-filled pore reveals the presence of iron-dolomite cement growing into the adjacent pore space (Fig. 5.17d).

Figure 5.17: Argon ion-milled back scattered SEM analyses of Middle Bakken moderate permeability sample (Courtesy: Tobi Kosanke, MOC, 2013).
These images indicate that the majority of the porosity was micro-porosity associated with detrital clay-filled pores.

**Figure 5.18** shows the end trim plug pictures before and after the test where the laminations was observed. CO₂ penetration was seen in the post-test pictures through the darker bands (fine-grained clay-rich laminations) more than through the white bands (quartz-rich laminations with dolomite grains). The permeability was calculated as **627 nd**. This was order of magnitude higher than the low-permeability sample which had the abundant calcite cement. Apparent gas filled unstressed porosity of the adjacent sample is **4.35%** (*Table 5.2*). Increase in porosity in comparison to the low-permeability sample is due to the contribution from the clay-filled pores through laminations.

**Figure 5.18**: Steady-state matrix permeability measurement of Middle Bakken moderate permeability sample.

### 3. High Permeability and High Porosity Middle Bakken Sample

**Figure 5.19** shows the thin section and CT scan of the sample. This sample was from Reunion Bay at a depth of 10591.05 ft. Thin section of 50x magnifications showed the laminations have no apparent micro-fractures so we assume the measured permeability is a matrix permeability. The matrix consists of detrital clays, microcrystalline dolomite, and detrital quartz. The porosity in this sample is clay-filled, but also occluded by dolomite cement.

XRD analysis, summarized in *Table 5.1* (core sample at 10591.05 ft), indicates that dominant mineral is quartz (47%) followed by 23% of carbonates primarily dolomite (14%), and moderate amounts of clays (12%). Illite accounts for a majority of the clay (10%). Considering the observations from the previous samples, higher permeability was expected due to the existence of the laminations, with the amount of clay-illite and dolomite content.
Figure 5.19: CT scan and thin section (50 x magnification) of Middle Bakken high permeability sample.

Figure 5.20 shows various magnifications of SEM images. Matrix permeability and porosity were expected to be higher in this sample due to following reasons:
- The abundance of dolomite and clays was significant (Fig. 5.20a).
- A micro-fracture was observed connecting the clay filled pores (Fig. 5.20b).
- Clay field pores are mostly surrounded by dolomite, followed by quartz (Fig. 5.20c).
- No pores created by dolomite dissolution (Fig. 5.20c and Fig. 5.20d).
- These images indicate that the majority of the porosity was micro-porosity associated with detrital clay-filled pores connected through micro-fractures.
The laminations are clearly observed on the end trim plug photos, shown in Fig. 5.21 with no indication of fractures. Sample and test details are summarized in Fig. 5.21. The permeability was calculated as 1249 nd. This was higher than any other measurements. Apparent gas filled unstressed porosity of the adjacent sample was measured as 5.09% (Table 5.2).

In summary, three rock textures were observed in the target Middle Bakken Lithofacies-3: (1) sandstone with pore-filling calcite cement with an average permeability of 0.00001 md and an average unstressed gas filled porosity of 1.3%, (2) argillaceous sandstone with pore-filling clays (primary...
intergranular porosity) connected to form laminations with an average permeability of 0.0001 md and an average unstressed gas filled porosity of 3.3%, (3) dolomitic to variably calcareous, argillaceous, slightly sandy siltstone with clay-filled pores with an average permeability of 0.001 md and an average unstressed gas filled porosity of 5.7%.

5.3 Fracture Properties

Because the matrix of the Bakken is extremely tight as illustrated in the previous section, fracture networks are crucial in successfully producing oil from a Bakken reservoir. Fracture networks also serve as the primary pathway during EOR application. Not only characterizing fractures observed in a core-scale but also it is crucial to understand the fracture intensity variation in a vertical and a spatial sense with respect to flexures, folds, faults, and fracture corridors. Fracture intensity is typically derived by core, image logs, structural curvature, and seismic curvatures (Nelson, 2012).

5.3.1 Fracture Intensity

Two vertical core sections from Lodgepole to Three Forks formation were used for the fracture intensity study in Bailey and Reunion Bay by Nelson, R. (2012). The first well is located in Bailey where the possible structures include both an anticlinal and synclinal fold based on seismic and structural curvatures. Figure 5.22 shows the fracture intensity curves for this well. Table 5.7 summarizes the average fracture intensity of each formation.

![Figure 5.22](image-url)

Figure 5.22: Fracture intensity log for the Well #1 in Bailey Field. O and PO refers to the combined number of fractures that were either open or partially open.
Table 5.7: Average fracture intensity numbers for the Well #1 in Bailey Field

<table>
<thead>
<tr>
<th>Fracture Intensity</th>
<th>Lodgepole</th>
<th>Upper Bakken Shale</th>
<th>Middle Bakken</th>
<th>Lower Bakken Shale</th>
<th>Three Forks</th>
</tr>
</thead>
<tbody>
<tr>
<td>All Fracs</td>
<td>4.462</td>
<td>0.385</td>
<td>0.932</td>
<td>0.000</td>
<td>2.333</td>
</tr>
<tr>
<td>O+PO Fracs</td>
<td>1.282</td>
<td>0.154</td>
<td>0.205</td>
<td>0.000</td>
<td>0.456</td>
</tr>
</tbody>
</table>

Figure 5.23 shows the fracture intensity curves for the second well in Reunion Bay. Table 5.8 summarizes the average fracture intensity of each formation. The properties of natural fractures derived from those core analyses were linked to reservoir simulation in Chapter 8.

Figure 5.23: Fracture intensity log for the Well #2 in Reunion Bay Field. O and PO refers to the combined number of fractures that were either open or partially open.

Table 5.8: Average fracture intensity numbers for the Well #2 in Reunion Bay Field

<table>
<thead>
<tr>
<th>Fracture Intensity</th>
<th>Lodgepole</th>
<th>Upper Bakken Shale</th>
<th>Middle Bakken</th>
<th>Lower Bakken Shale</th>
<th>Three Forks</th>
</tr>
</thead>
<tbody>
<tr>
<td>All Fracs</td>
<td>2.673</td>
<td>0.238</td>
<td>0.537</td>
<td>0.979</td>
<td>0.375</td>
</tr>
<tr>
<td>O+PO Fracs</td>
<td>2.257</td>
<td>0.19</td>
<td>0.222</td>
<td>0.667</td>
<td>0.054</td>
</tr>
</tbody>
</table>

In both wells, the highest fracture intensity was observed in Lodgepole formation. As discussed in Chapter 3, there is not enough storage in Lodgepole formation to benefit from the presence of fractures. However, in Middle Bakken, there exists micro-fracture system with matrix storage.

5.3.2 Fracture Aperture

In Bailey field, besides the core used in the fracture intensity study (Fig. 5.22), the cores from two additional wells were also available for analyses to support the fracture properties. For each core, facies and macrofracture analyses were conducted according to methodologies described in Nelson (2001).
and US Bureau of Reclamation (1998). The SEM was also used to identify and characterize microfractures for aperture, length, and orientation (Kurtoglu, et al., 2013a). The micro-fracture aperture for various Middle Bakken lithofacies was measured between 2.4 and 17 µm (Fig. 3.8). With respect to fracture height and length, they were assumed to be bed-contained in the reservoir simulation (Chapter 8). Thus, maximum fracture height was constrained using the vertical resolution of the cells in the simulation model.

5.3.3 Fracture Orientation

Fracture orientation data came from Nelson’s study (2011) where he combined the horizontal cores of known wellbore azimuth, borehole image logs, and the data from the published literature. As shown in Fig. 5.24, the basin displays a dominant NE to ENE fracture trend. The oriented core, indicated by E in Fig. 5.24, represents the fracture orientation in Bailey field. The horizontal CMI, indicated by F in Fig. 5.24, shows the fracture orientation in Reunion Bay. This supports the decision to develop North Dakota Bakken wells in the north-south orientation by increasing the contact area with fractures. Multi-stage fracturing which is designed to be initiated from the wellbore to the east-west direction also advances the fracture network.

**Figure 5.24:** Map of natural fracture orientation for the eastern half of the Williston Basin.
5.3.4 Fractured Sample Permeability

A core plug from Middle Bakken Lithofacies 3 with visible fractures was selected to observe the effect of fractures on flow mechanism. Figure 5.25 shows the existence of micro-fracture in the thin section as well as in CT scan image. This sample consists of extensive calcite cemented pores as in the low matrix permeability sample (Section 5.2.7).

Figure 5.25: CT scan and thin section (50x magnification) of Middle Bakken fractured sample.

For better characterization, 400 times magnification of thin sections was observed (Fig. 5.26): one with plane transmitted light view and the other with epifluorescent lighting techniques (light blue).

Figure 5.26: Thin section (400x magnification) of Middle Bakken fractured sample with (a) plane transmitted light view and with (b) epifluorescent lighting technique.
Monocrystalline quartz grains were abundant (white color) with non-skeletal calcerous grains. Minor dolomite (tan-brown color), detrital clays (brown color), and pyrite (black color) were also found. Epifluorescent lighting techniques (light blue) was used to observe micropores but no visible pores detected using standard petrographic techniques. So, observed porosity was limited to micro-fractures.

Figure 5.27 shows the end trim pictures of pre- and post-permeability measurement and sample details. Although the rock texture consists of pore-filling calcite cement, the measured permeability of this sample was **0.0298 md** due to the existence of micro-fractures. This clearly indicates that even in this rock texture without the presence of laminations, the fluid flow path for the hydrocarbons occurs due to the existing micro-fractures.

![Figure 5.27: Steady-state matrix permeability measurement of Middle Bakken fractured sample.](image)

**5.3.5 Fracture Relative Permeability**

Fracture relative permeability curves were generated using Corey’s equations **(Eq. 5.20- Eq. 5.24)**. The end-point relative permeability and saturations were summarized in **Table 5.9**.

**Table 5.9: Parameters to generate three phase relative permeability for fracture**

<table>
<thead>
<tr>
<th>Fracture Properties</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Irreducible water saturation, $S_{wr}$</td>
<td>0.05</td>
</tr>
<tr>
<td>Irreducible oil saturation, $S_{or}$</td>
<td>0.05</td>
</tr>
<tr>
<td>Absolute permeability, (md)</td>
<td>0.05</td>
</tr>
<tr>
<td>Relative gas permeability at $S_{wr}$</td>
<td>0.5</td>
</tr>
<tr>
<td>Relative oil permeability at $S_{or}$</td>
<td>0.8</td>
</tr>
<tr>
<td>Relative water permeability at $S_{or}$</td>
<td>0.4</td>
</tr>
</tbody>
</table>
Corey exponents for fracture were assumed as: \( n_w = 1.5, n_o = 2.0, n_l = 2.0, n_g = 1.5 \). Figure 5.28 plots the fracture relative permeability data in water-oil and liquid-gas systems. These curves were used for the fracture region of the dual-porosity compositional model (Chapter 8). The Stone’s second three phase oil relative permeability model was included, particularly for the waterflood simulation (Stone, 1973).

![Figure 5.28](image)

**Figure 5.28:** Gas-liquid and water-oil relative permeability data for fracture.

### 5.3.6 Stress Dependent Fracture Permeability

The same experiment as for the matrix was conducted to measure fracture permeability as a function of increasing effective stress. A core with visible micro-fractures was selected for the experiment as shown in Fig. 5.29.

![Figure 5.29](image)

**Figure 5.29:** Confining stress effect on fracture permeability (Courtesy: Richard Rosen, MOC, 2013).
Point 1 to 3 in Fig. 5.29 represents the dilation process (hydraulic fracturing) and from 3 to 10 represents the compression due to depletion. More than 90% of the fracture permeability was lost during depletion process. The laboratory results for both for matrix (Section 5.2.6) and fracture were included in the reservoir simulation model by generating rock compaction tables.

5.4 Imbibition Tests

This section presents the experimental observations and results related to the low and high salinity brine imbibition mechanisms. The effect of rock and fluid properties on these mechanisms is also explained.

5.4.1 Wettability Restoration

Crude sample from a producing well in Bailey field (presented in Chapter 4) was filtered to less than 0.5 micron particle using a pressurized filtration system. The selected core samples (Fig. 5.1 and Fig 5.2) were submersed in a pressure vessel with dead crude at the temperature of 221°F and the pressure of 500 psi for four weeks to restore wettability. The gas filled pore volume was determined by Boyle’s law. The oil volume was calculated by dividing the weight difference before and after aging by the density of oil (0.852 g/cc). Table 5.10 lists the results of oil volume for each plug.

<table>
<thead>
<tr>
<th>Field</th>
<th>Core #</th>
<th>Depth ft</th>
<th>Initial Weight</th>
<th>Post Aging Weight</th>
<th>Oil Weight</th>
<th>Oil Volume</th>
<th>Oil Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bailey</td>
<td>1</td>
<td>10847.55</td>
<td>18.666</td>
<td>18.865</td>
<td>0.199</td>
<td>0.234</td>
<td></td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>10847.65</td>
<td>66.419</td>
<td>67.159</td>
<td>0.740</td>
<td>0.869</td>
<td></td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>10847.85</td>
<td>65.224</td>
<td>65.875</td>
<td>0.651</td>
<td>0.764</td>
<td></td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>10850.45</td>
<td>18.392</td>
<td>18.459</td>
<td>0.067</td>
<td>0.079</td>
<td></td>
</tr>
<tr>
<td>Reunion Bay</td>
<td>5</td>
<td>10591.05</td>
<td>26.536</td>
<td>26.916</td>
<td>0.380</td>
<td>0.446</td>
<td></td>
</tr>
</tbody>
</table>

The initial water and oil saturations were not known. Therefore, the fluid saturations via Dean-Stark were determined using neighboring samples (done by Weatherford Laboratories). These fluid saturations were used as a reference to estimate representative fluid saturation for cores in Table 5.1. In the Dean-Stark test, the samples were weighed and then subjected to hot toluene extraction to boil off water. The samples were further extracted with chloroform-methanol azeotrope to remove hydrocarbons.
and any salt. Each sample was then dried and weighed. The pore volume was measured and then the fluid saturations were determined. **Table 5.11** gives the saturation measurements for the neighbor four samples.

<table>
<thead>
<tr>
<th>Field</th>
<th>Depth ft</th>
<th>Water Saturation percent</th>
<th>Oil Saturation percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bailey</td>
<td>10847.3</td>
<td>29.5</td>
<td>52.1</td>
</tr>
<tr>
<td>Bailey</td>
<td>10848.5</td>
<td>19.4</td>
<td>53.1</td>
</tr>
<tr>
<td>Bailey</td>
<td>10851.1</td>
<td>18.2</td>
<td>60.5</td>
</tr>
<tr>
<td>Reunion Bay</td>
<td>10590.5</td>
<td>33.0</td>
<td>36.8</td>
</tr>
</tbody>
</table>

**Table 5.11**: Summary of Dean-Stark fluid saturations

### 5.4.2 Spontaneous Imbibition with Low Salinity Water

The spontaneous imbibition experiment included four Bailey core plugs (**Table 5.10**). The core locations were indicated in **Fig. 5.1** and **Fig. 5.2**. The XRD results and core plug properties are summarized in **Table 5.1** and **5.2**, respectively. The spontaneous imbibition was performed using Amott cell (**Fig. 5.30**). The cell is unable to withstand high temperature and pressure. The core was held by a spring wire and was suspended off the bottom to insure an even assessment of an imbibition fluid.

![Figure 5.30: Amot cell setup for the Middle Bakken spontaneous imbibition tests.](image)

The test duration was three weeks. Aged core samples were submersed in imbibition fluid in the glass container. Two of them were filled with 2 weight of % KCl brine (20,000 ppm) and the other two
with the fracturing fluid. The fracturing fluid, sent from the Bailey field, was also a low-salinity water around 5,000 ppm. The reason for using 2 weight of % KCl was to test the effect of low salinity water on imbibition mechanism without the inclusion of additional additives and surfactants within the frac fluid. According to the Dean-Stark results shown in Table 5.11, these samples are expected to have an average 22% of water saturation. As shown in Chapter 4, Bakken produced water from Bailey has a high-salinity water of approximately 285,000 ppm.

The section below illustrates the core characterization and the observation of imbibition test for each plug. In an attempt to contrast the imbibition mechanisms, the core data measurements were reviewed (see Table 5.1).

Figure 5.31 shows the end trim pieces of the four core plugs before aging them. No apparent micro-fractures were observed in Sample #1 and Sample #4, whereas Sample #2 and Sample #3 have visible fractures. The reason to use non-fracture and fracture cores is to compare their effect on imbibition mechanism.

![Figure 5.31: End trim pieces of the imbibition test samples.](image)

All samples except Sample #4 have visible laminations observed in the microscopic pictures (Fig. 5.32). Darker color was observed through these laminations which is very obvious in the Sample #1 picture.

![Figure 5.32: Microscopic pictures of the imbibition test samples.](image)
Figure 5.33 shows the thin section from each core plug. Their XRD results are summarized in Table 5.1. The laminations mentioned above were characterized by high volume of clay and replacement alternating with higher volume of quartz and feldspar. The darker bands indicate those fine grained clay-rich laminations. The clays mostly consist of illite. Sample #4 was characterized by large mud-rimmed burrows observed some with sand or cement fills in Fig. 5.32d. The mineralogy of this sample mostly involves calcite and followed by quartz.

![Thin section images](image)

**Figure 5.33:** Thin section of the imbibition test samples.

Matrix permeability measurement of a neighbor core plug to Sample #1 is 671 nD, whereas the matrix permeability for sample #4 is 11.7 nD. Boyle’s Law porosity is 4.35% for Sample #1, 3.13% for Sample #2, 2.84% for Sample #3, and 1.44% for Sample #4. Post-saturation oil volume for each sample was summarized in Table 5.10. Sample #4 has the minimum oil volume of 0.079 cc after the saturation.

Sample #1 and Sample #2 were immersed in a 2 weight % of KCL brine. Sample #3 and Sample #4 were immersed in low salinity-frac fluid. Figure 5.34 shows the status at Day 6 of imbibition. Oil droplets forming over the every surface of Sample #1, Sample #2, and Sample #3. However, this behavior is contradictory with the previous droplet test which shows the core is preferentially oil-wet. Thus, oil should not be displaced from the core sample by imbibing brine.

In Sample #2 and Sample #3, oil was appeared along the darker bands considered as fine-grained clay-rich laminations. However, minor oil droplets were observed along the white bands considered as relatively coarse grained quartz-rich laminations with dolomite grains. In contrast to other samples, very few oil droplets were observed on the surface of Sample #4. This was due to low matrix permeability, low porosity, and the abundance of calcite in this sample. This sample also had a moderate amount of clay, but they were not connected through the sample to create the laminations that provides the flow path and hydrocarbon storage.

Before the imbibition experiments, several ion-milled SEM images were taken to identify the pore structure. They are presented in Fig. 5.14 (low permeability sample) and in Fig. 5.17 (high permeability sample). After the imbibition experiment, new SEM images from cores used in the experiments (Sample #1 and Sample #4 in Fig. 5.34) were prepared to determine any differences.
Figure 5.34: Core pictures after Day 6 of imbibition (Courtesy: William Mickelson and Richard Rosen, MOC, 2013).

Figure 5.35 shows the 10 µm magnification SEM of Sample #1 and the 50 µm magnification SEM of Sample #4. The porosity in Sample #1 is limited to detrital clay-filled primary intergranular pores. Oil appears to be within this illite and clay-grains filled pore in Fig. 5.35a. The mechanism of how this clay filled pores behave under low salinity will be explained in the following sections. The porosity in Sample #4 is filled with calcite cement. Again in Sample #4, oil was appeared to be in the clay-filled slot-pore. However, there were not so many of these pores due to the abundance of calcite cement. This is the reason that Sample #4 shows poor imbibition.

To compare the Middle Bakken pore structure with the Lower Bakken shale pore structure, the following SEM image of the Lower Bakken is presented in Fig. 5.36. As can be seen the porosity of the Lower Bakken shale is limited to detrital clay-filled, intergranular pores. Lower Bakken is organic shale.
which is made up of mineral grains and kerogen. The black is kerogen in slit pores. The grains are clays, quartz, carbonate, pyrite, etc.

**Figure 5.35:** Argon ion-milled back scattered SEM analyses of post-imbibition uncleaned (a) Sample #1 and (b) Sample #4 (Courtesy: Tobi Kosanke, MOC, 2013).

**Figure 5.36:** Argon ion-milled SEM of Lower Bakken Shale (Courtesy: Tobi Kosanke, MOC, 2013).
Imbibition Test Comparison among Four Core Plugs

After three weeks of imbibition, the samples were removed from the cell to quantify the amount of oil displaced from the samples. Since these were too tight samples, most of the oil displaced stayed on the surface of the samples while some was accumulated at the top of the sample by gravity segregation. After taking the samples from the cell, no clay precipitation was observed. Additionally, no significant emulsion was detected which was quantified by comparing the density of emulsion with the density of brine and fracturing fluid.

Because the volume of produced oil was very small; it was hard to record this information through time. Instead, after the completion of the experiments, dry cloth was used to clean the surface of the rock to absorb the oil as well as the oil accumulated at the top. Knowing the dry cloth weight and oil-wetted cloth weight, the amount of oil displaced was calculated as well as the oil volume knowing the density of oil (Table 5.12). Additionally, the samples were weighed and results were compared with the post-oil aging weight and volume. The imbibed water amount was calculated for each sample by the following approach:

\[
\text{Imbibed Water Weight} = \text{Post Imbibition Weight} - [\text{Post Aging Weight} - \text{Displaced Oil Volume}] \quad [5.24]
\]

Using 2 weight % of KCL brine density (1.014 g/cm³), the amount of water volume imbibed in each core was estimated (Table 5.12). For all the samples, a higher oil volume was displaced than the water imbibed in the core.

<table>
<thead>
<tr>
<th>Field</th>
<th>Core #</th>
<th>Depth ft</th>
<th>Post Oil Saturation</th>
<th>Post Imbibition</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Post Aging Weight g</td>
<td>Oil Volume cm³</td>
</tr>
<tr>
<td>Bailey</td>
<td>1 10847.55</td>
<td>18.865</td>
<td>0.234</td>
<td>18.848</td>
</tr>
<tr>
<td></td>
<td>2 10847.65</td>
<td>67.159</td>
<td>0.869</td>
<td>67.164</td>
</tr>
<tr>
<td></td>
<td>3 10847.85</td>
<td>65.875</td>
<td>0.764</td>
<td>65.868</td>
</tr>
<tr>
<td></td>
<td>4 10850.45</td>
<td>18.459</td>
<td>0.079</td>
<td>18.460</td>
</tr>
</tbody>
</table>

Two approaches were followed to measure the oil recovery from the low-salinity imbibition experiments:
(1) Rock-Eval pyrolysis and (2) Dean-Stark test. The objective was to provide confidence in oil recovery calculation by comparing two different techniques.
**Rock-Eval pyrolysis:** Organic matter geochemistry was evaluated via Rock-Eval pyrolysis for the preserved rock samples at the representative plug depths. In the pyrolysis technique the organic matter in sedimentary rocks was characterized by heating the rock samples in the absence of oxygen. During this process, it is necessary to use the experimental temperatures considerably higher than those normally found in the subsurface so that appreciable reaction can occur in a reasonably short time (Barker, 1974).

In our oil recovery calculation, free oil content (S1) was required to calculate initial oil in place in the rock. Rock-Eval S1 represents milligrams of hydrocarbons that are already present in one gram of rock while Rock-Eval S2 represents the hydrocarbons that are thermally induced by the pyrolysis process. Rock-Eval S1 values are typically minimum values for free oil in the absence of contamination and oil-based mud (Jarvie et al., 2011). It can be used as a qualitative measure since some portion of the producible hydrocarbon is evaporating during the Rock-Eval testing process. In our calculation, S1 yield was used to represent the native state oil in the rock.

The following equations were used to calculate the native state oil weight and original oil in place (OOIP) of each sample (Table 5.13).

\[
\text{Native State Oil Weight} = S1_{\text{unextracted}} \times \text{Initial Weight} \tag{5.25}
\]

\[
\text{OOIP} = \text{Post Oil Saturation Volume} \times \text{Volume} + \text{Native State Oil Volume} \tag{5.26}
\]

Table 5.13 includes the Rock-Eval S1, S2 for un-extracted sample, native-state oil weight, volume, OOIP, and recovery factor. Recovery factor for both approaches were calculated by dividing the recovered oil volume during the imbibition by OOIP.

**Table 5.13:** Rock-Eval measurement to calculate oil recovery for the imbibition samples

<table>
<thead>
<tr>
<th>Field</th>
<th>Core #</th>
<th>Depth ft</th>
<th>S1 unextracted mg/g</th>
<th>S2 unextracted mg/g</th>
<th>Native State Oil g</th>
<th>Native State Oil Volume cm$^3$</th>
<th>OOIP cm$^3$</th>
<th>Recovery %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bailey</td>
<td>1</td>
<td>10847.55</td>
<td>3.01</td>
<td>2.03</td>
<td>0.05</td>
<td>0.06</td>
<td>0.29</td>
<td>57</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>10847.65</td>
<td>2.68</td>
<td>2.39</td>
<td>0.16</td>
<td>0.19</td>
<td>1.06</td>
<td>64</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>10847.85</td>
<td>2.46</td>
<td>1.68</td>
<td>0.14</td>
<td>0.16</td>
<td>0.93</td>
<td>67</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>10850.45</td>
<td>2.27</td>
<td>1.38</td>
<td>0.04</td>
<td>0.05</td>
<td>0.12</td>
<td>24</td>
</tr>
</tbody>
</table>
**Dean-Stark test**: Oil saturations from Dean-Stark test were referenced to determine average initial oil saturation in the rock (Table 5.11). Then, the measured bulk volume and unstressed porosity values were used to estimate OOIP. Table 5.14 summarizes those measurements with the recovery factor.

**Table 5.14**: Dean-Stark approach to calculate oil recovery for the imbibition samples

<table>
<thead>
<tr>
<th>Field</th>
<th>Core</th>
<th>Depth</th>
<th>Apparent Gas Filled Unstressed Porosity</th>
<th>Bulk Volume</th>
<th>Pore Volume</th>
<th>OOIP</th>
<th>Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>#</td>
<td>ft</td>
<td>%</td>
<td>cm³</td>
<td>cm³</td>
<td>cm³</td>
<td>%</td>
</tr>
<tr>
<td>Bailey</td>
<td>1</td>
<td>10847.55</td>
<td>4.35</td>
<td>7.27</td>
<td>0.32</td>
<td>0.39</td>
<td>43</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>10847.65</td>
<td>3.13</td>
<td>25.79</td>
<td>0.81</td>
<td>1.27</td>
<td>54</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>10847.85</td>
<td>2.84</td>
<td>25.28</td>
<td>0.72</td>
<td>1.12</td>
<td>55</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>10850.45</td>
<td>1.44</td>
<td>6.91</td>
<td>0.10</td>
<td>0.13</td>
<td>23</td>
</tr>
</tbody>
</table>

From both approaches, the average oil recovery was around 50 to 60% for high permeability laminated clay-rich samples (Sample #1, Sample #2, and Sample #3). It was 23% oil recovery for the low permeability calcite-rich sample (Sample #4).

**5.4.3 Wettability of Laminated Sample**

The water imbibition and the corresponding oil recovery observed in the imbibition tests were not expected considering the fluid droplet test results (Section 5.2.2). This encouraged using another rock sample within the depth of the core plugs (10,847.75 ft) to perform the similar fluid droplet wettability experiment. The depth of the rock sample is from a high-matrix permeability of 671 nd and consists of 8.4% clays, 50.7% quartz, 9.7% calcite, and 3.9% dolomite.

Several time steps of the experiment are summarized below and the images are presented in Fig. 5.37.

1. 2 weight % of KCL brine was dropped on the sample surface.
2. It took 17 second for brine to spread partially on the surface.
3. The second drop of 2 weight % of KCL brine and the first crude were dropped.
4. The first drop of crude underwent the brine droplet showing more oil-wet tendency on the surface.
5. The second drop of crude was taken place.
6. The second oil drop took 4 second to soak-in.
Figure 5.37: Fluid drop wettability test with the laminated core sample.

This experiment showed that the core surface was preferentially oil wet while the sample in itself could have mix-wettability considering the imbibition of water.

5.4.4 Spontaneous Imbibition with High Salinity Water

A neighbor core plug to Sample #3 (10847.85 ft) was used in a high salinity Bakken formation brine of 285,000 ppm imbibition test. The mineralogy of the sample contains 9.2% clays (mostly illite), which is similar to the Sample #3. The purpose is to use same rock type of core and investigate difference in a result under high versus low salinity brine imbibition.

![High Salinity Experiment Start: 11-01-2012](image1)  ![Low Salinity Experiment Start: 11-07-2012](image2)

(a) High-salinity  (b) Low–salinity

Figure 5.38: Amot cell experiment with (a) high-salinity formation water at Day 5 and (b) low–salinity brine at Day 12 (Courtesy: William Mickelson and Richard Rosen, MOC, 2013).
The high salinity brine imbibition was performed for seven days. After 5 days, much lower brine imbibition was observed than that of the low-salinity case (Fig. 5.37). Figure 5.37a shows only few oil droplets forming on the surface of the sample after the high-salinity brine imbibition test. This sample was removed from the cell and put into another cell filled with 2 weight % of KCl brine. Figure 5.38b shows the core picture from the low salinity experiment a day after the low salinity experiment started. It can be seen low salinity brine has a greater spontaneous imbibition with more oil droplets forming on surface of the sample. This effect is similar to Sample #3 (Fig. 5.34c), that is most of oil was appeared along the laminations. The experiments presented so far demonstrate the impact of brine salinity on the imbibition process.

5.4.5 Spontaneous Imbibition at High Pressure and High Temperature

The following experiment was to investigate the imbibition mechanisms under the high pressure and temperature conditions using Sample #5 (Table 5.10) from Reunion Bay. The basic and post-saturation core properties were provided in Table 5.2 and Table 5.3. The plug contains 12% clays, 47% quartz, 9% calcite, and 14% dolomite with high permeability of 1249 nd and high porosity of 5.69%.

The experimental setup, Fig. 5.39, was built at the Marathon Technical Laboratory (Mickelson and Rosen, 2012).

The sample was placed horizontally into a sight cell such that the end face of the core can be imaged by a 5 megaPixel IP camera. This was to observe the spontaneous imbibition occurring under elevated pressures and temperatures. The sight cell was mounted in a horizontal airflow oven. A fiber optic lighting system was used to illuminate the imbibition events.

Figure 5.39: Experimental setup schematic for the high pressure and high temperature spontaneous imbibition.
The sight cell was initially filled only with 2 weight % of KCl brine. The sight cell was pressured to 3500 psi and the oven set to maintain temperature at 48 °C. The total brine volume in the sight cell was about 150 cc. The first part of the test lasted for 12 hrs. Figure 5.40 shows the time elapsed images from the experiment at time 1 hr, 5 hr, and 12 hr. As in the previous tests at normal room temperature (Section 5.4.2), the oil droplets were observed on the surface of the sample. The amount of oil was not able to be measured for this sample.

Figure 5.40: Images after 2 weight % KCL spontaneous imbibition at 3500 psi and 48 °C showing the oil droplets (Courtesy: William Mickelson and Richard Rosen, MOC, 2013).

Figure 5.41 demonstrates the microscopic picture before the test with the arrows indicating the clay-filled laminations. The picture on the left in Fig. 5.41 superimposed the post-imbibition surface area on pre-imbibition microscopic picture. The larger oil drops formed preferentially along the laminations.

After 12 hr the cell was disassembled, and refilled with 2 weight % of KCl brine. The oil on the sample surface from the previous low salinity brine test was removed when the cell was disassembled. The pump was drained of brine and refilled with CO₂. The cell was again pressurized to 3500 psi (above CO₂ minimum miscibility pressure) and the temperature was maintained at 48 °C.

Figure 5.41: Images before and after 2 weight % of KCL spontaneous imbibition at 3500 psi and 48 °C showing the oil droplets along the laminations.
A bleed valve on top of the sight cell was used to slowly bleed 10 cc’s of brine from the system which was displaced by CO₂ from the pump. This was done to ensure that brine in the lines had been replaced with CO₂ to decrease the time it took for the CO₂ and brine to reach equilibrium. Figure 5.42 shows the several images recorded through the experiment.

Figure 5.42: Images showing the incremental oil drops after carbonated water imbibition at 3500 psi and 48 °C.

After 16 hours, additional oil droplets formed on the surface of the sample besides the laminations. The more concentration of the carbonated brine, the more and the larger oil droplets formed. Although oil recovery was not able to be quantified in both experiments, it was observed that initial recovery was obtained through low-salinity system and additional oil could be produced with the addition of CO₂.

5.4.6 Theory and Mechanism
The common observations from the experiments demonstrated:

- The clay content in the porous medium is crucial for the low salinity EOR effect as well as for the flow capacity.
- The low salinity brine has a superior EOR effect than the high salinity brine.
- The presence of CO₂ further increased the EOR at high pressure and temperature.
These effects prompt us to investigate the chemical mechanisms behind the saline EOR process in conjunction with formation brine composition, oil properties, and clay type and its amount in Middle Bakken formation.

Several core floods in literature have conducted to study incremental recovery via low salinity brine injection (Tang and Morrow, 1997; Morrow et al., 1998; Tang and Morrow, 1999a; Tang and Morrow, 1999b; McGuire et al., 2005; Zhang and Morrow, 2006, Zhang et al., 2007). A new mechanism that takes into account the effects of pH and salinity on adsorption of acidic, basic organic components onto different clay minerals, clay properties like ion exchange capacity and selectivity, and oil properties was proposed by Austad et al. (2010) and RezaeiDoust et al. (2010).

Based on our Bakken studies, the proposed mechanism to increase oil recovery by low salinity brine are listed below:

- The formation needs to contain a typical clay type with sufficient quantity.
  - Clay content, mostly illite, was measured in Middle Bakken porous medium (Table 5.1). It was more dominant in the laminated lithofacies of Middle Bakken.

- Oil must contain polar components.
  - Bakken oil has polar components shown in SARA and MPLC analyses (Table 4.2). Aromatics, which are slightly polarizable, are in the range of 27 to 46 weight %. Resin and asphaltene have an average of 7.5 weight %.
  - TAN (acid components) and TBN (base components) represent active polar components in the oil which Bakken has 0.09 and 1.16 mg KOH/g (Table 4.3). There appears to be no restrictions to the type of polar components provided that they are present.

- Formation brine must contain divalent cations (Ca$^{2+}$ and Mg$^{2+}$)
  - Bakken formation water salinity is around 285,000 ppm with the initial pH around 5.7 (Table 4.5). The divalent ions of Mg$^{2+}$ and Ca$^{2+}$ consist of 1,400 ppm and 20,000 ppm of the total dissolved solids (Table 4.6).

The properties of Bakken formation are suitable for the low-salinity EOR application. Therefore, more study is still needed to understand its interaction with crude, clay type, reservoir temperature, and a possible CO$_2$ application.

As illustrated previously in ion-milled SEM pictures, the Middle Bakken matrix pores are filled with clay (Fig. 5.17 and Fig. 5.20) and the hydrocarbons are contained in these pores (Fig. 5.35). The clay type, identified by XRD, is mostly illite (Table 5.1). The mineralogy includes 0 to 0.2 weight % of kaolinite, 4.9 to 13.1 weight % of illite/mica, zero weight % of smectite, and 0.5 to 1.5 weight % of kaolinite. The rock samples with the clay-illite filled pores through laminations provided higher matrix permeability (Section 5.2.7) and resulted in higher oil recovery from the imbibition tests (Section 5.4.2).
Lager (2007) showed that there is a linear correlation between clay content and oil recovery for the low-salinity EOR. However, some clays can be swollen due to the low salinity effect. Another important feature of the clays is their cation exchange capacity (CEC). Clay minerals with high CEC tend to be more favorable to low salinity effects (Austad et al., 2010). The higher the CEC the greater the adsorption onto clay minerals.

Montmorillonite is a member of the smectite family which has a high CEC (Table 5.15), but it is a swelling clay. Illite has also relatively high ion exchange capacity and a non-expanding mineral. Because the type of the clay in Bakken is mostly illite, the low-salinity frac fluid injection did not result in formation damage.

Table 5.15: Properties of actual clay minerals (International Drilling Fluids (IDF), 1982)

<table>
<thead>
<tr>
<th>Property</th>
<th>Kaolinite</th>
<th>Illite/Mica</th>
<th>Montmorillonite</th>
<th>Chlorite</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cation exchange cap. (meq/100g)</td>
<td>3-15</td>
<td>10-40</td>
<td>80-150</td>
<td>10-40</td>
</tr>
<tr>
<td>Surface area BET-N₂ (m²/g)</td>
<td>15-25</td>
<td>50-110</td>
<td>30-80</td>
<td>140</td>
</tr>
</tbody>
</table>

For further investigation, the rock samples from the two core sections (Fig. 5.1 and Fig. 5.2) were taken to measure CEC. Table 5.16 shows these results. As expected, the interval which has the clay-rich laminations exhibits slightly higher CEC than the interval has the calcite-cement fills. However, overall these values are relatively lower than those observed in conventional clastic reservoirs.

Table 5.16: Summary of Cation Exchange Capacity results for Middle Bakken

<table>
<thead>
<tr>
<th>Depth ft</th>
<th>Thin Section Interpretation</th>
<th>Aggregate Mass g</th>
<th>CEC meq per 100g</th>
</tr>
</thead>
<tbody>
<tr>
<td>10847.45</td>
<td>Clay-rich laminations</td>
<td>10.004</td>
<td>0.504</td>
</tr>
<tr>
<td>10850.40</td>
<td>Mud-rimmed burrows with calcite cement fills</td>
<td>10.005</td>
<td>0.451</td>
</tr>
</tbody>
</table>

The mechanism of oil mobilization resulting from salinity gradients postulated by different investigators:

1. Decrease in ion binding by Lager et al. (2007) and wettability alteration due to ionic double layer effect by Ligthelem et al. (2009)
2. Local increase in pH close to the clay surface by Austad et al. (2010) and RezaeiDoust et al. (2010)
3. Osmotic effects by Fakcharoenphol (2013)
The following sections summarize each mechanism and its relation to Bakken imbibition experiments.

1. Decrease in Ion Binding and Wettability Alteration

   Multivalent cations in the brine such as Ca\(^{2+}\) and Mg\(^{2+}\) act like bridges between the negatively charged oil and clay minerals in Fig. 5.43 (Anderson, 1986; Lager et al., 2006, 2007; Ligthelem et al., 2009).

   Ligthelem et al. (2009) explained the wettability alteration process by low salinity in terms of expansion of electrical double layer effects. Lowering the overall salinity level (the electrolyte content) by reducing the multivalent cations in the brine solution reduces the screening potential of the cations. This yields expansion of the electrical diffuse double layers that surround the clay and oil particles. This in turn yields increased electrostatic repulsion between the clay particle and the oil shown in Fig. 5.44a.

   ![Figure 5.43: Binding mechanism between clay and oil (From Ligthelem et al., 2009).](image)

   Once the repulsive forces exceed the binding forces via the multivalent cation bridges, the oil particles may be desorbed from the clay surfaces. This would result in a reduction in the fraction of the rock surface that has been coated by oil and this in turn implies a change in wetting state towards increased water-wetness.

   ![Figure 5.44: Cartoons of bonding between clay surface and oil in a low saline and high saline brine environment (From Ligthelem et al., 2009).](image)
This mechanism is reverse in a high salinity environment. In presence of a sufficiently high salinity level, sufficient positive cations (Ca\(^{2+}\) and Mg\(^{2+}\)) are available to screen-off their negative electrical charges with suppression of the electrostatic repulsive forces. This causes a low level of the negative electrical potential (Fig. 5.43b). So, oil can react with these clay particles to form organo-metallic complexes (Rueslatten, 1994). It makes the clay surface extremely hydrophobic and causes local oil-wetness (Clements, 1982).

The theory of Liguehlem et al. (2009) was aligned with the observation from our fluid droplet experiments using various Middle Bakken rock types, (Fig. 5.4 and Fig. 5.37), showing preferentially oil-wet characteristic. Once the core plugs were exposed to low salinity water (frac fluid of around 5000 ppm or 2 weight of % of KCL), the more water-wet behavior caused a greater water imbibition, especially for the core plugs with the clay-rich laminations. In contrast, once the core sample was submersed in high salinity water (formation water of 285,000 ppm), the oil-wet behavior caused poor water imbibition (Fig. 5.38a). In summary, this theory suggests that a decrease in salinity will increase the size of the ionic double layer between the clay and oil interfaces, facilitating the release of organic material.

2. Local Increase in pH close to Clay Surface

Austad et al. (2010) and RezaeiDoust et al. (2010) explained the low salinity EOR mechanism with the local increase in pH close to the clay surface. As discussed earlier, the clay type has an important effect because the clay acts as a cation exchanger with a relatively large surface area. Initially, both basic and acidic organic materials are adsorbed onto the clay together with multivalent cations, especially, Ca\(^{2+}\), from the formation water. A chemical equilibrium is then established at actual reservoir conditions (pH, temperature, and pressure).

When the water with a lower salinity than formation brine is injected into the reservoir, the equilibrium associated with the brine-rock interaction is disturbed, and a net desorption of cations occurs (especially Ca\(^{2+}\)). To compensate for the loss of cations, protons, H\(^+\), from the water close to the clay surface adsorb onto the clay, a substitution of Ca\(^{2+}\) by H\(^+\) is taking place. This creates a local increase in pH close to the clay surface as illustrated by the following equation:

\[
\text{Clay - Ca}^{2+} + \text{H}_2\text{O} = \text{Clay - H}^+ + \text{Ca}^{2+} + \text{OH}^- \quad \text{[5.27]}
\]

The local increase in pH close to the clay surface causes H\(^+\) and acidic material as in an ordinary acid-base proton transfer reaction, as shown by Eq. 5.28 and Eq. 5.29:

\[
\text{Clay - NHR}^{3+} + \text{OH}^- = \text{Clay} + \text{R}_3\text{N} + \text{H}_2\text{O} \quad \text{[5.28]}
\]
Clay - RCOOH + OH⁻ = Clay + RCOO⁻ + H₂O [5.29]

Once the desorption of initially adsorbed cations (Ca²⁺) from the clay is achieved (Eq. 5.27) with low-salinity water injection, the pH of the water is increased. This is required to remove some of the adsorbed organic material on the clay surface (Fig. 5.45).

Considering the Bakken imbibition test started with the high salinity water, limited water imbibition was observed even though the sample contains a large amount of clay-rich laminations (Fig. 5.38a). In this case, adsorbed Ca²⁺ onto clay minerals prevents the release of organic materials from the clay-filled pores. With pH =5.7 of Bakken formation brine, clay particles can act a cation exchange material. However, high-salinity brine imbibition experiment suggests that the mechanism primarily relies on the expansion of electrical double layers and the desorption of initially adsorbed cations (Ca²⁺), then to lesser extent on cation exchange processes.

![Figure 5.45: Low-salinity wettability alteration mechanism (From RezaeiDoust, et al, 2010).](image)

The adsorption of organic materials onto the clay is very sensitive to pH (Austad et al., 2010). Their study showed that the adsorption increased as pH value decreased. The adsorption of acidic and basic compounds can be improved by CO₂ because dissolved CO₂ in the formation brine decreases pH value. This decrease in pH favors the adsorption of the carboxylate group, RCOO⁻ onto the clay, however at the expense of forming a bridge mechanism and precipitation by Ca²⁺. As shown earlier, the oil production from the low-salinity imbibition test took short time to see the oil droplets, after which no additional oil droplets were observed. However, additional oil recovery occurs in the high pressure and
high temperature, and low-salinity imbibition test followed by CO₂ imbibition. Besides causing oil swelling, viscosity reduction and other mechanisms (see Section 4.3) CO₂ could also favor the adsorption of remaining organic materials onto clay. These hydrocarbons can then be released due to low salinity effect, results in more oil production. Further studies are necessary to understand the change in rock and fluid properties in the presence of CO₂.

3. Osmotic Effect

Fakcharoenphol (2013) showed that osmotic pressure promotes water-oil counter-current flow to produce oil. The difference in salinity between fracturing fluid and formation brine creates water concentration gradient and osmotic pressure, inducing flow from low-salinity water in fractures into matrix pore containing high-salinity brine. This continues until the solute concentrations reach equilibrium. In the low-salinity experiments, low-salinity brine or frac fluid was imbibed through the clay-rich high-salinity matrix pores until salinity reaches equilibrium.

Because typical fracturing fluid comprises low-salinity water (approximately 5000 ppm) while Bakken formation brine is high-salinity (approximately 285,000 ppm), significant salinity difference between fluid inside fractures and matrix is expected as fracturing fluid is typically occupied space inside fracture network created during hydraulic fractures. Thus, osmotic pressure effect could be significant during hydraulic fracturing and early production periods. However, the effect will decrease with time as high-salinity formation brine that was flushed away during the hydraulic fracturing flows back and blends with fracturing fluid which increasing salinity inside the fractures, and the low-salinity fracturing fluid is imbibed into matrix reducing salinity inside the matrix. Thus, it decreases the salinity difference. As a result, a minimal osmotic effect would be expected during long term production period.

The theoretical osmotic pressure was generated by Fakcharoenphol (2013) for different salinity values between formation and low salinity brine at different temperatures. He used TOUGHREACT™ simulator (a chemical reaction simulator) to calculate water activity. The osmotic pressure for the high-salinity Bakken formation brine opposed to fresh water is calculated approximately 5000 psi (Fig. 5.46). The initial high oil rate observed upon fracturing and after a period of shutin time, may be attributed to the high osmotic pressure.
Figure 5.46: Theoretical osmotic pressure created by salinity differences between Bakken formation brine and fresh water at 240 °F.
CHAPTER 6
WELL TEST ANALYSIS

Pressure transient test applications in unconventional reservoirs are far more complicated than similar tests in conventional reservoirs because of the differences in porosity and permeability, well geometry, well completion, and stimulation techniques.

The laboratory measured core permeability for the Middle Bakken Formation ranges from $10^{-4}$- $10^{-5}$ md (Chapter 5). However, well production rates, and the permeabilities calculated for these rates do not support the low core permeability values. To quantify reservoir permeability in a realistic way, several different flow tests shown in Fig. 6.1 were used. The tests were conducted at progressively larger scales of measurement.

Mini-DST has the shortest flow duration (few hours) and a minimal wellbore storage effect. Mini-DST is also used to measure permeability at different reservoir intervals in the same formation to identify the optimal location for well completion.

The second level test is a mini-frac test, which provides several hours of pressure and flowrate measurements. The mini-frac test also provides the minimum horizontal stress, as well as the fluid leakage coefficient, which can be used to calculate formation permeability.

The third longest duration test is a pressure buildup test lasting several days. The long-pressure buildup test displays well flow regime, which can be history-matched to obtain reservoir pressure and permeability. Finally, the longest duration test is the production history of the well. To analyze the production history, the normalized rate-transient analysis is used (Chapter 7).

It is evident from the data shown in Fig. 6.1 that there is at least one order of magnitude difference between core-measured permeability ($10^{-4}$-$10^{-5}$ md) and field-measured permeability ($10^{-1}$-$10^{-2}$ md). This is a clear indication of the contribution of a micro-fracture system to the productivity of Bakken Formation. The implication of the presence of a micro-fracture network is the main reason to explore the application of waterflooding and CO₂ injection in Bakken Formation to enhance oil production.

Operationally, mini-DST is used in a vertical open-hole well to identify intrinsic formation flow capacity of multiple zones. This vertical well is then cased and an interval with the highest flow capacity can be further tested with mini-frac. This provides information about fracture properties for the design of original hydraulic fracturing stimulation. Lastly, lateral section is drilled and followed by multi-stage frac completion and stimulation. During stimulation of the first stage, mini-frac test can be also used in a horizontal well. In the absence of any mini-DST or mini-frac test, pre- and post-stimulation pressure buildups can estimate effective permeability with and without having hydraulic fractures in the reservoir.
This chapter presents the applications of well testing for unconventional reservoirs including field examples from wells in Reunion Bay, Bailey, and Murphy Creek fields. The following sections provide the closed-from formulations for different flow regimes and field applications for (1) mini-DST, (2) mini-frac, and (3) pressure build up test. The rate transient analysis (RTA) approach will be addressed in Chapter 7. The integration of well testing and RTA analyses with the simulation results will be shown in Chapter 8.

6.1 Mini-DST

Mini-DST application in unconventional reservoirs was a new innovation first applied in Bakken Formation to obtain pressure transient data from an open-hole section of a vertical well. Such data was used to estimate formation flow capacity.

The mini-DST has increased reliability of pressure transient tests because the formation interval of interest is produced at a constant rate with negligible wellbore storage effects. The operation of mini-DST tool requires much less time than that of classic DST, and multiple zones can be tested sequentially to assess the individual zone deliverability. This creates an ideal situation for pressure transient testing.
because the change in bottom-hole pressure as a function of time should obey the theoretical equations during the first few minutes of testing.

An overlay of all the pressure drawdown and buildup results from various intervals was compared on a single plot to identify the most productive interval. Additionally, conventional pressure transient analyses were performed to interpret pressure drawdown and buildup tests.

6.1.1 Description of Mini-DST

The mini-DST was originally designed to collect down-hole fluid samples. Its modular design it was modified for interval production testing using dual-inflatable packers that isolate approximately 3 feet of a borehole interval for production. The entire formation is open along the borehole wall so the fluid flow area is nearly one thousand times larger than that of conventional probe.

![Figure 6.2: Mini-DST dual packer configuration (Schlumberger™).](image)

**Figure 6.2** is a schematic of a dual-packer mini-DST system. Mini-DST tool uses the conventional Wireline Formation Tester (WFT) configured with a dual-packer module and downhole pump. Tests are conducted by inflating the dual-packer module. The formation fluid is pumped out from the packer-isolated wellbore interval to conduct pressure drawdown and buildup tests in the interval.

The pump is specially designed to pump at a slow, constant rate even when working against a variable differential pressure. Therefore the formation interval produces at a constant rate with very minimal wellbore storage effects. The pump is placed directly above the packers and the strain and quartz
crystal gauges that record pressure are located in the lower part of the tool, below the packer interval as shown in Fig. 6.2.

Lost circulation material must be avoided because of the presence of small orifices in the toolstring. Furthermore solid particles in the mud system originating from the cuttings must be circulated out. A screen is installed at the entrance of the flowline to prevent the entry of any remaining cuttings into the flowline. More details about the mini-DST tool and its applications are provided in Kurtoglu et al.’s paper (2012a).

6.1.2 Mini-DST Interpretation

Before performing the mini-DST in the field, numerical reservoir simulation was used to design tests with different permeabilities and average formation properties. This resulted in different pressure drawdown and buildup profiles for the various modeled zones. The objective was not only to estimate pressure responses from different zones but also to guide any required operational changes (pump rate, differential pressure, etc.) prior to conducting mini-DST. Once the field test data was gathered the simulated pressure profiles were used to determine the range of permeability by superimposing the field test response with respect to the simulated ones. Multiple modeling scenarios show that permeability can be estimated within a realistic order of magnitude. For an example, Fig. 6.3 shows the simulation results for 0.01, 0.001 and 0.00001 md isotropic permeability with a 15-minute flow period at 2 cc/second, followed by one hour of pressure buildup.

Figure 6.3: Pre-test modeling- Mini-DST reservoir simulation pressure-time plots for a 0.01, 0.001 and 0.00001 md isotropic permeability.
Due to low permeability in the Bakken Formation, the pressure was not expected to build up to static conditions within an hour. The rate of change in pressure responses was compared among tested zones to determine their relative deliverability of the various zones. Assuming Darcy flow, with constant rate and viscosity, the relative change in pressure is directly proportional with the formation deliverability. Therefore, a formation with a larger pressure buildup rate should have a higher flow capacity.

After a preliminary interpretation of pressure data as discussed above, conventional pressure transient test analysis was performed to identify flow regimes and derive permeability. The pressure behavior can be easily modeled with a limited entry well model since the dual-packer system creates an isolated interval for the tested zone. A schematic of the theoretical flow regimes is illustrated in Fig. 6.4.

During a mini-DST test, two important types of transient flow regimes may be identified: radial flow and spherical flow (Fig. 6.4). The use of pressure derivative together with pressure response enables the identification of different flow regimes when they are plotted against time on a logarithmic scale. Existence of spherical flow indicates vertical contribution which may be again followed by radial flow if the reservoir permeability is high and test duration is long enough.
Figure 6.5: Log-log pressure and pressure derivative plot for a typical mini-DST showing various flow regimes.

**Early-Radial Flow**

Figure 6.5 illustrates the log-log diagnostic plots for an idealized mini-DST which demonstrates various flow regimes of pressure transient response. It starts with the early radial flow that is developed from the dual packer interval to the wellbore. Zero slope is observed on the pressure derivative response. For any well configuration and well completion, radial flow regime can be analyzed using the derivation for a single-phase flow toward a fully penetrating well of radius $r_w$ in an infinite-acting reservoir:

$$\Delta p = \frac{162.6qB\mu}{kh} \left[ \log(t) + \log \left( \frac{k}{\varphi \mu c, r_w^2} \right) - 3.228 + 0.8686S \right]$$  \[6.1\]

Where:

$$\Delta p = p_i - p_{of}(t)$$  \[6.2\]

$\Delta p$ versus $\log t$ should give a straight line with a slope of, $m_r$:

$$m_r = -\frac{162.6qB\mu}{k, h_w}$$  \[6.3\]
Where:

\[ k_r = \sqrt{k_x k_y} \]  \hspace{1cm} [6.4]

**Spherical Flow**

Once the vertical contribution of flow within the packer interval becomes significant, spherical flow will develop with a straight line slope of -1/2 (negative half slope) in the derivative response. During that period the pressure change is proportional to \( \frac{1}{\sqrt{t}} \). The pressure change during spherical flow is given by the following equation (Joseph and Koederitz, 1985):

\[
\Delta p = \frac{70.6 q B \mu}{k_s r_s} - \frac{2453 q B \mu \sqrt{\phi \mu e}}{k_{sp}^{3/2}} \frac{1}{\sqrt{t}} \]  \hspace{1cm} [6.5]

Where:

\[
\Delta p = p_i - p_{wfi} (t) \]  \hspace{1cm} [6.6]

\( \Delta p \) versus \( \frac{1}{\sqrt{t}} \) yields the following slope:

\[
m_{sp} = \frac{2453 q B \mu \sqrt{\phi \mu e}}{k_{sp}^{3/2}} \]  \hspace{1cm} [6.7]

Where:

\[
k_{sp} = \sqrt[3]{k_x k_y k_z} = \sqrt[3]{k_r^2 k_y} \]  \hspace{1cm} [6.8]

**Late-Radial Flow**

Lastly, late radial flow is developed if the reservoir permeability is high and buildup time is long enough. The same radial flow equation as in Eq. 6.1 is used to calculate reservoir permeability.
6.1.3 Mini-DST Field Applications

The mini-DST and analysis procedure described above have been applied to several vertical well openhole completions in Bakken fields. This section provides examples of two Bakken mini-DST test analyses examples. Each test was planned with a thirty-minute flow period followed by one hour buildup.

Field Example -1

The first test was performed in Reunion Bay Field, North Dakota, where many horizontal wells have already been drilled within the Middle Bakken formation. The expectation was to test prospective intervals within the Middle Bakken Formation and also identify other additional productive zones above and below the Middle Bakken. The test points include nine intervals as shown in Fig. 6.6. Six of the tested intervals were in non-shale formations (one in the Three Forks, three in the Middle Bakken, one in the Scallion, and one in the Lower Lodgepole Formation). Three of the tested intervals were in shale formations (two in the Lower Bakken Shale, one in the Upper Bakken Shale).

![Figure 6.6: Mini-DST well test intervals in an open hole vertical well in Reunion Bay Field.](image)

The designed test duration for drawdown and buildup could not be accomplished for the Lower and Upper Bakken shales because of low flow potential (Fig. 6.7).
Figure 6.7: Mini-DST pressure drawdown and build up data from a nine-interval field test, Well-1, Reunion Bay Field.

In Fig. 6.7, the laminated Middle Bakken Formation (test point number 3) exhibited the lowest pressure drawdown and the highest pressure buildup. The drawdown from this interval was 2562 cc. This interval test was further analyzed to identify flow regimes.

Figure 6.8 shows the mini-DST 3 well history and the log-log pressure and pressure derivative responses with type-curve model match. The development of early radial flow regime was observed in the diagnostic plot that was used to estimate near-wellbore permeability. This implies the effective permeability of the reservoir which is a combination of fracture and matrix permeability. Although this is not a quantitative method for permeability estimation, it represents the flow capacity of the reservoir.

Figure 6.8: (a) Pressure and flowrate history match plot, (b) pressure and pressure derivative plot for the Middle Bakken mini-DST 3 in Well-1, Reunion Bay Field.
The rate was not constant during the test (Fig. 6.8), which may have affected the overall comparison among the tested intervals. This revealed the importance of having a constant rate pump which was implemented in the subsequent wells with success. Table 6.1 summarizes the Saphir™ (KAPPA pressure transient analysis software) model parameters and the test results for the Middle Bakken mini-DST 3 in Reunion Bay Field.

**Table 6.1:** Pressure transient analysis results using Saphir™ for the Middle Bakken mini-DST 3 in Well-1, Reunion Bay Field

<table>
<thead>
<tr>
<th>Wellbore and Tool Parameters</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$r_w$</td>
<td>0.25 ft</td>
</tr>
<tr>
<td>$H$</td>
<td>3 ft</td>
</tr>
<tr>
<td>$z_w$</td>
<td>1.5 ft</td>
</tr>
<tr>
<td>$h_w$</td>
<td>2.26</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid Properties</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$B$</td>
<td>1.33 bbl/STB</td>
</tr>
<tr>
<td>$\mu$</td>
<td>0.4 cp</td>
</tr>
<tr>
<td>$c_i$</td>
<td>$1.64 \times 10^{-6}$ 1/psi</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reservoir Parameters</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_i$</td>
<td>6354 psi</td>
</tr>
<tr>
<td>$\phi$</td>
<td>0.05</td>
</tr>
<tr>
<td>$k_r h$</td>
<td>0.039 md-ft</td>
</tr>
<tr>
<td>$k_r$</td>
<td>0.013 md</td>
</tr>
<tr>
<td>$k_z/k_r$</td>
<td>0.08</td>
</tr>
</tbody>
</table>

The analytical solution for radial flow (Eq. 6.3) was also applied using the identical fluid parameters as those used in Saphir™. The section where zero-slope (radial flow) was observed on the pressure derivative plot (Fig. 6.8) was further analyzed in the semi-log plot (Fig. 6.9). Then, the slope of the straight line passing through the last section of the semi-log plot was used to calculate the effective horizontal permeability. The result of this analysis, shown in Fig. 6.9, yielded a permeability of 0.026 md.

Lastly, the volume of the reservoir that has been investigated during the test was calculated using the radius of investigation equation:

$$r_{inv} = 0.0325 \left( \frac{k_r t}{\phi \mu c_i} \right)^{1/2} \quad [6.9]$$

Radius of investigation, $r_{inv}$, was calculated to be 5 feet, using total porosity and permeability in Saphir™ model. The data are tabulated in Table 2. This calculated radius of investigation is consistent
with the material balance calculations using a depletion pressure drop of 2500 psi in a 3-ft near-wellbore cylindrical rock volume between packers.

**Figure 6.9:** Radial flow analysis of the Middle Bakken mini-DST 3 in Well-1, Reunion Bay Field.

**Table 6.2:** Radius of investigation for the Middle Bakken mini-DST 3 in Well-1, Reunion Bay Field

<table>
<thead>
<tr>
<th>µ</th>
<th>0.4</th>
<th>cp</th>
</tr>
</thead>
<tbody>
<tr>
<td>qB</td>
<td>0.78</td>
<td>RB/day</td>
</tr>
<tr>
<td>h_w</td>
<td>3</td>
<td>ft</td>
</tr>
<tr>
<td>φ</td>
<td>0.05</td>
<td></td>
</tr>
<tr>
<td>m_r</td>
<td>645</td>
<td>psi/log cycle</td>
</tr>
<tr>
<td>k_r</td>
<td>0.026</td>
<td>md</td>
</tr>
</tbody>
</table>

**Field Example -2**

The mini-DST was also applied to Well-2 in Bailey Field to identify potential productive formations in addition to the original Middle Bakken Formation. The tests were conducted in eight reservoir formations including four test points in the Three Forks, two in the Middle Bakken, and two in the Scallion. **Figure 6.10** shows the Scallion Formation (test point number 8) exhibits a different pressure response compared to other formations. The drawdown reached a steady flowing pressure followed by a buildup which attained pressure stabilization after one hour. This clearly indicates the high flow capacity potential in that tested zone and encouraged further analysis to determine flow regimes. The drawdown from this interval during the test was 4028 cc of formation fluid.
**Figure 6.10:** Mini-DST pressure drawdown and build up data from an eight-interval test, Well-2, Bailey Field.

**Figure 6.11** shows the log-log pressure and pressure derivative responses with a type-curve model match and a pressure history match model from the Scallion formation mini-DST 8. In the diagnostic plot the early radial flow regime was developed followed by spherical flow. The vertical contribution during spherical flow, believed to take place outside of the packer interval, allowed us to estimate effective permeability. Although this is not an exact permeability measurement, unlike a core measurement, it reflects the formation response for the contact area.

**Figure 6.11:** (a) Pressure and flowrate history match plot; (b) Pressure and pressure derivative plot for the Scallion mini-DST 8 in Well-2, Bailey Field.

The field data was history matched using a limited entry vertical well model (**Fig. 6.11**) and the results were summarized in **Table 6.3**. A reservoir pressure of 5896 psi was obtained in the near-wellbore...
region from the history-match model while the effective permeability was calculated to be approximately 0.11 md.

Table 6.3: Pressure transient analysis results using Saphir™ for the Scallion mini-DST 8 in Well-2, Bailey Field

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellbore and Tool Parameters</td>
<td></td>
</tr>
<tr>
<td>r_w</td>
<td>0.36 ft</td>
</tr>
<tr>
<td>H</td>
<td>3 ft</td>
</tr>
<tr>
<td>z_w</td>
<td>1.5 ft</td>
</tr>
<tr>
<td>h_w</td>
<td>2.26 ft</td>
</tr>
<tr>
<td>Fluid Properties</td>
<td></td>
</tr>
<tr>
<td>B</td>
<td>1.51 bbl/STB</td>
</tr>
<tr>
<td>μ</td>
<td>0.35 cp</td>
</tr>
<tr>
<td>c_t</td>
<td>1.64 x 10^-5 1/psi</td>
</tr>
<tr>
<td>Reservoir Parameters</td>
<td></td>
</tr>
<tr>
<td>P_i</td>
<td>5,896 psi</td>
</tr>
<tr>
<td>ϕ</td>
<td>0.05</td>
</tr>
<tr>
<td>k_Ih</td>
<td>0.353 md-ft</td>
</tr>
<tr>
<td>k_r</td>
<td>0.11 md</td>
</tr>
<tr>
<td>k_d/k_r</td>
<td>0.008</td>
</tr>
</tbody>
</table>

The analytical solution for spherical flow (Eq. 6.7) was applied using the identical fluid properties as those used in Saphir™ model. The negative half slope interval of the derivative response was used to calculate a permeability of 0.034 md (Fig. 6.12).

Figure 6.12: Spherical flow analysis of the Scallion mini-DST 8 in Well-2, Bailey Field.
The radius of investigation for the mini-DST Scallion 8 test was calculated using Eq. 6.9. Using a permeability of 0.11 md and total porosity of 0.05 (fraction), the radius of investigation was calculated to be 20 ft (Table 6.4).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\mu$</td>
<td>0.35  cp</td>
</tr>
<tr>
<td>$\phi$</td>
<td>0.05</td>
</tr>
<tr>
<td>$c_i$</td>
<td>1.64E-05 1/psi</td>
</tr>
<tr>
<td>$T$</td>
<td>1 hours</td>
</tr>
<tr>
<td>$k_r$</td>
<td>0.11 md</td>
</tr>
<tr>
<td>$r_{inv, total system}$</td>
<td>20.1 ft</td>
</tr>
</tbody>
</table>

Table 6.4: Radius of investigation for the Middle Bakken mini-DST 8 in Well-2, Bailey Field

In the most promising Bakken intervals, mini-DST results show a formation effective permeability between 0.01 and 0.1 md, while core plug measurements yield permeabilities that range from 0.0001 to 0.001 md. Such information is crucial in decisions regarding application of improved and enhanced oil recovery techniques for the Bakken Formation as well as identification of potential landing zones for primary recovery.

6.2 Mini-frac

Mini-frac is also known as diagnostic fracture injection test (DFIT). Mini-frac is another in-situ pressure transient test to derive necessary reservoir properties such as permeability and reservoir pressure prior to original hydraulic fracturing. Because it is difficult to inject fluid into or withdraw fluid from tight rock, mini-frac tests have been utilized to establish a pressure decline response. The mini-frac test tactics to evaluate the reservoir and geomechanical characteristics of the pay zone were summarized in Cramer and Nguyen’s study (2013). Their study was concluded from the analyses of numerous mini-frac tests conducted in unconventional reservoirs.

The test procedure, interpretation of mini-frac data, and the Bakken field examples are presented in the following sections. The mini-frac field examples are the same wells as those in the mini-DST (Section 6.1). The objective was to compare the results with a different scale of pressure transient testing method. The mini-DST approximately 0.016 bbls of formation fluid was produced during the drawdown period and then buildup data were analyzed to estimate formation capacity. In contrast, in a mini-frac approximately 25 to 60 bbls of water is injected into the formation and fall-off data was analyzed after fracture closure to derive reservoir properties.
6.2.1 Description of Mini-frac

A mini-frac test is a fracture injection fall-off test. It is used to evaluate productive potential and the economic feasibility of a reservoir that undergoes fracture stimulation. It provides information about the fracture properties such as fracture closure pressure and leakoff mechanism and the reservoir properties such as effective permeability and reservoir pressure. The test can be conducted in both vertical and horizontal wells. In vertical wells the well is cased and a selected interval is perforated. In horizontal wells a mini-frac test is performed on the first-stage prior to a multi-stage fracture stimulation.

Figure 6.13 shows a typical mini-frac testing sequence. The well is first filled with water and low rate fluid (usually water, diesel, or gas) is then injected into the formation until the hydraulic pressure exceeds fracture pressure gradient. The pressure continues buildup until formation breakdown occurs (i.e. reach the initial fracture pressure). Fluid injection at the surface is continued until wellhead pressure stabilizes. After the injection period the pump is shut down resulting in an instantaneous shut-in pressure (ISIP) as shown in Fig. 6.13. ISIP is the net of wellbore and near wellbore friction pressure, also described as the incipient fracture extension pressure (Barree et al., 2009). Sufficient shut-down time is required for fracture closure to occur. After the reaching closure the pressure decline is measured through time. The post-closure fall-off data are then analyzed to identify pseudo-linear and pseudo-radial flow regimes and derive key reservoir parameters.

![Figure 6.13 Typical fracture injection test plot.](image-url)
Because the injection rate is crucial to interpret mini-frac test, it must be precisely recorded using the surface pressure gauge with 0.01-0.1 psi resolution and sample rate of 1-5 seconds. Injection volume for ultralow permeability formations is in the range of 1 to 12 bbls of fluid with a low injection rates ranging from 0.1 to 3 bbl/min (Cramer and Nguyen, 2013). The reason for the small volume and low rate of injection was to minimize fracture length in order to shorten fracture closure time so that both pseudo-linear and pseudo-radial flow regimes could be identified. Pseudo-radial flow regime is required to calculate transmissibility and pore pressure (Gringarten et al., 1974; Cinco-Ley et al., 1981).

For the Bakken tests presented in this research, the wells were shut in downhole and the data was recorded via the surface gauge. The hydrostatic head calculated for 3% KCl was added to the surface gauge pressure to yield downhole pressure. The injection volume was approximately 25 to 50 bbls with an average injection rate of 2 bbl/min.

6.2.2. Mini-frac Interpretation

Mini-frac provides results from both pre- and post-closure analysis. For pre-closure analysis, G-function and square-root of shut-in time plots are used to identify fracture closure and leakoff mechanism. Identification of leakoff mechanisms aids in designing pad volume requirements and maximum sand concentration. Fracture closure pressure data obtained through a mini-frac also provides insight for the maximum injection pressure for EOR application. In the modeling of injection scenarios, fracture closure pressure drives the maximum limit for injection pressure so that no fractures are generated in the reservoir during the injection cycle. For pressure-falloff data, After Closure Analysis (ACA) is used to identify the flow regimes including pseudo-linear and pseudo-radial.

G-function Plot

G-function plot displays three plots against G-function including pressure (p), derivative (dp/dG) and superposition derivative (G.dp/dG). The objective is to find the closure pressure by drawing a linear through the origin on the semi-log derivative (G.dp/dG) plot and determine a possible leakoff mechanism.

The G-function is a dimensionless function of shut-in time normalized to pumping time. The dimensionless pumping time used in G-function is defined as (Nolte, 1988):

\[
\Delta t_D = \frac{t - t_p}{t_p}
\]

[6.10]

Where t represents the elapsed total time from the start of fracture initiation and t_p is the total pumping time from fracture initiation. Assuming high fluid efficiency (low leakoff) in low permeability
reservoirs, the surface area of the fracture varies linearly with time during fracture propagation. With this assumption, the dimensionless time ($\Delta t_D$) is used to compute an intermediate function:

$$g(\Delta t_D) = \frac{4}{\pi} \left( (1 + \Delta t_D)^{1.5} - \Delta t_D^{1.5} \right)$$ [6.11]

Then, G-function is derived from Eq. 6.11 as follows:

$$G(\Delta t_D) = \frac{4}{\pi} [g(\Delta t_D) - g_o]$$ [6.12]

Where $g_o$ is the dimensionless loss-volume function at shut-in ($t=t_p$). For both G-function and square-root of shut-in time analysis, the pressure ($p$), the first derivative ($dp/dt$), and the semilog derivative ($tdp/dt$) versus time plots are used. In a G-function plot, the time axis represents G-time, whereas in square root of time plot, time represents the square root of shut-in time. The use of a square root plot in combination with a G-function plot is helpful to correctly identify fracture closure pressure (see Section 6.2.2b).

There are four major leakoff mechanism types are normal leakoff, pressure-dependent leakoff, fracture tip extension and transverse storage/fracture-height recession (Barree et al., 2009). Figure 6.14 represents the characteristic behavior of G-function plots for each leakoff mechanism.

**Normal leakoff** is observed when the composite reservoir system permeability is constant. The reservoir may exhibit only matrix permeability or have a fracture response in which the flow capacity of the secondary fracture system does not change with pore pressure.

**Pressure dependent leakoff** (PDL) occurs when the fluid loss rate changes with pore pressure in the rock surrounding the fracture. In the existence of pressure dependent leakoff system, there is a change in the transmissibility of the reservoir fissure or fracture system that dominates the fluid loss rate. PDL is only apparent when there is substantial stress dependent permeability in a composite dual-permeability reservoir.

**Fracture tip extension leakoff** occurs in very low permeability reservoirs where the decline in wellbore pressure observed after shut-in. This may be caused by the dissipation of the pressure transient established in the fracture during pumping.

**Fracture-height recession and transverse fracture storage leakoff** is caused by an excess stored volume of fluid in the fracture at shut-in relative to the expected surface area of the fracture for a planar, constant height geometry model. The leakoff occurs only through a thin permeable bed and that the fracture extends in height to cover impermeable strata with no leakoff.
The use of each diagnostic plot including G-function plot, square root plot, log-log pressure and pressure derivative plot, and ACA plot is explained in detail for the major four leakoff types in the study of Barree et al. (2009).

**Square Root Shut-in Time Plot**

The objective of the square root of time plot is to check closure consistency. This plot displays the same functions as the G-function plot versus the square root of shut-in time. The closure point, shown in an example later, should correspond to a local maximum of pressure derivative but not for all the leakoff mechanisms. Analysis of G-function and square root plots provides defined closure pressure, leakoff mechanism, and primary closure parameters.

**After Closure Analysis Plots**

ACA is applied to the post closure pressure-fall off part of the test (Fig. 6. 13) to detect possible flow regimes (Talley et al., 1999). ACA includes the pressure difference and semi-log derivative versus square root linear flow function plot.
After the fracture transient dissipates, the reservoir linear flow period can continue for some time depending on reservoir permeability and injected volume to create the fracture. Linear flow period exhibits a derivative slope of \( \frac{1}{2} \) on ACA plot from which reservoir pressure can be derived using a Cartesian linear flow plot. If the decline period is sufficient to reach a pseudo-radial flow regime, the transmissibility and permeability can also be estimated using a Cartesian radial flow plot.

The after-closure pseudo-linear flow analysis is adapted from Carslaw and Jaeger’s (1959) heat transfer analysis. If pressure in the fracture is essentially constant during injection, then the pressure decline after closure behaves same as the thermal-conductivity decay:

\[
p(t) - p_i = m_L F_L(t, t_c)
\]  [6.13]

Where \( t_c \) is the time to closure with time zero set as the beginning of pumping, \( p_i \) is the initial reservoir pressure, and \( F_L \) is the linear flow time function.

\[
F_L(t, t_c) = \frac{2}{\pi} \sin^{-1} \left( \frac{t_c}{t} \right), \quad t \geq t_c
\]  [6.14]

The coefficient or Cartesian-plot slope, \( m_L \), is defined as:

\[
m_L = C_T \sqrt{\frac{\pi \mu}{k \phi c_i}}
\]  [6.15]

Where \( C_T \) is total leakoff coefficient and \( c_i \) is total compressibility. From Eq. 6.14 and Eq. 6.15 the pressure decline during the linear-flow period can then be written in terms of reservoir diffusivity, storage, total fluid loss coefficient, and closure time as follows.

\[
p(t) - p_i = C_T \sqrt{\frac{\pi \mu}{k \phi c_i}} \left( \frac{2}{\pi} \sin^{-1} \left( \frac{t_c}{t} \right) \right), \quad t \geq t_c
\]  [6.16]

When spurt loss exists, the initial linear-flow behavior follows a different time behavior but eventually conforms to the behavior of \( F_L(t, t_c) \). After this behavior is established the linear-flow slope
analysis can be used, in conjunction with reservoir parameters and the pre-closure decline analysis to
determine the magnitude of spurt loss.

The late-time pressure decline evolves to pseudo-radial flow allowing transmissibility \((kh/\mu)\) to
be determined using a method similar to a Horner analysis. After-closure radial-flow is a function of the
injected volume, reservoir pressure, formation transmissibility, and closure time. Their relationship is
provided in the following equations using the radial flow time function, \(F_R\).

\[
p(t) - p_i = m_R F_R(t, t_c)
\]  \hspace{1cm} \text{[6.17]}

Where \(m_R\) is functionally equivalent to the Horner slope for conventional testing.

\[
F_R(t, t_c) = \frac{1}{4} \ln \left(1 + \frac{16/\pi^2 t_c}{t - t_c}\right)
\]  \hspace{1cm} \text{[6.18]}

Thus, a Cartesian plot of pressure versus the radial-flow time function yields reservoir pressure
from the y-intercept and the slope \((m_R)\) that permits determination of transmissibility.

\[
\frac{kh}{\mu} = 251,000 \left(\frac{V_i}{m_R t_c}\right)
\]  \hspace{1cm} \text{[6.19]}

With \(k\), \(h\), \(m_R\) expressed in oil field units, \(t_c\) in minutes and \(V_i\) is injected volume (bbl).

6.2.3. Mini-frac Field Applications

The mini-frac procedure described above was applied to several vertical and horizontal wells in
Bakken. The test results were analyzed using the mini-frac module in Saphir™.

Field Example -1

The first mini-frac testing and analyses were performed across the same Middle Bakken zone
where mini-DST 3 (Fig. 6.6) was performed. After the completion of mini-DST test in an open hole the
wellbore was cased and a mini-frac test was performed.

A total of 41 bbls of water at 1.85 bbl/min was injected following breakdown. Fracture extension
pressure was observed at 8815 psi (0.85 psi/ft). The well was shut in to monitor pressure falloff.
Diagnostic plots indicated that fracture closure was 8303 psi (0.78 psi/ft). The G-function plot suggested the pressure transverse storage leakoff with a closure occurs at 41.9 G-time.

Only pseudo-linear flow was exhibited in the after-closure period. Initial pore pressure was estimated as 7810 psi (0.74 psi/ft). Assuming a Middle Bakken thickness of 51 ft and an oil viscosity of 0.39 cp, an effective permeability of 0.006 md was calculated.

The disadvantage of having the vertical mini-frac test is the uncertainty about the tested interval thickness while calculating the permeability. As shown in Chapter 3, the Middle Bakken formation has five different lithofacies with varying flow capacity. The target lithofacies is the laminated zone with a thickness ranging from 10 to 15 ft. It would be more reliable permeability estimation if the mini-frac test was conducted in a horizontal well going through the target landing zone. After this specific vertical well was produced for almost two years, it was converted into a horizontal well drilled in the target Middle Bakken laminated zone. Another mini-frac test was performed on the first-stage perforation prior to fracture stimulation and then completed with 15-stage swell packer completion. A total of 26.5 bbls of water at an average rate of 1.9 bbl/min was injected. Fracture extension pressure was observed at 8110 psi. Figure 6.15 shows the job history plot.

![Figure 6.15](image)

**Figure 6.15** History plot for the field example-1, Reunion Bay Field.

**Figure 6.16** displays G-function and square root of time plot. The G-function derivative signature has a concave shape below the straight line through the origin and tangent to the semilog derivative at the point of the fracture closure. This behavior represents the transverse storage leakoff mechanism. This is caused by an excess stored volume of fluid in the fracture at shut-in relative to the expected surface area of the fracture for a constant height geometry model. The leakoff occurs only through a thin permeable bed and the fracture extends vertically to cover impermeable strata with no leakoff (Barree et al., 2009).
At shut-in there is a large volume of fluid stored in the fracture and the leakoff rate relative to the stored volume is small, hence the pressure decline is small. As the fracture closure empties the rate of leakoff relative to the remaining stored fluid accelerates and the pressure declines more rapidly.

Figure 6.16 also shows the square root of time plot, which was used to check closure consistency. The closure point corresponded to a local maximum of the pressure derivative. A fracture closure of 7654 psi (0.73 psi/ft) was observed via square root of time plot at a G-time of 8.15.

Figure 6.16 G-function and square root of time plot for the field example-1, Reunion Bay Field.

Figure 6.17 shows ACA plot with the linear and radial flow lines. Pseudo-linear flow was developed and had a transition into pseudo-radial flow.

Figure 6.17 ACA plot including flow regime lines for the field example-1, Reunion Bay Field.

The pseudo-linear section was analyzed on a linear flow time plot ($F_L$ in Eq. 6.14) shown in Fig. 6.18. The resulting pore pressure is 6916 psi (0.66 psi/ft). The comparison with the initial mini-frac pore
pressure estimation reveals that 894 psi of depletion is observed in the vicinity of the wellbore after two years of production. This is still above bubble point pressure of 2530 psi in Reunion Bay PVT Sample #2 (Chapter 4).

Figure 6.18 ACA linear flow plot for the field example-1, Reunion Bay Field.

Flow capacity was derived from the pseudo-radial section using radial flow time \( F_R \) in Eq. 6.18 and Horner time \( (t_p + dt/t_p) \) plots. Because pseudo-radial flow was not clearly observed, the calculated permeability derived from the end part of the linear section represents the maximum estimated permeability. Assuming a Middle Bakken thickness of 51 ft and an oil viscosity of 0.39 cp, an effective permeability of 0.044 md was calculated (Fig. 6.19).

The comparison between vertical and horizontal mini-frac tests for the same well show that in the latter test, permeability is an order of magnitude higher, G-function time is lower at fracture closure, and pore pressure is lower (due to 2 years of depletion).

Figure 6.19 ACA radial flow plot and Horner plot, for the field example-1, Reunion Bay Field.
Field Example -2

The second mini-frac test and analyses were performed on a horizontal well which had the mini-DST shown in the previous section (Fig. 6.10). This horizontal well was drilled through Scallion formation.

A total of 25 bbls of water was injected between 2.00 and 3.50 bbl/min for 12 minutes following breakdown into the toe section of the horizontal well (Fig. 6.20). Fracture extension pressure (ISIP) was 6593 psi (0.64 psi/ft).

![Fracture Initiation Pressure](image1)

**Figure 6.20** History plot for the field example-2, Bailey Field.

Diagnostic plots indicated that the fracture closure was 6391 psi (0.62 psi/ft) at a G-time of 1.32 (Fig. 6.21). Pressure dependent leak-off (PDL) was observed from G-function behavior (hump above the straight line). This was the indication of substantial stress dependent permeability in a composite dual permeability reservoir. The fracture closure time was confirmed with the use of the square root of time plot (Fig. 6.21). The closure time is 0.19 hr. In comparison to the Middle Bakken test (Example 1), it took a much shorter amount of time for the fracture to close in the Scallion Formation.

![Fracture Closure](image2)

**Figure 6.21** G-function and square root time plot for the field example-2, Bailey Field.
In the ACA plot (Fig. 6.22), pseudo-linear and pseudo-radial flows were observed.

![ACA plot](image)

**Figure 6.22** ACA plot including flow regime lines for the field example-2, Bailey Field.

The pseudo-linear flow plot estimated a pore pressure of 5154 psi (0.51 psi/ft) (Fig. 6.23). Assuming a thickness of 13 ft and an oil viscosity of 0.35 cp, a permeability of 0.70 md was calculated from the radial time plot (Fig. 6.23). The mini-frac test analysis for this well also calculated a permeability of 0.11 md and a reservoir pressure of 5896 psi.

![ACA plots](image)

**Figure 6.23** ACA linear and radial flow plots for the field example-2, Bailey Field.

### 6.3 Pressure Buildup

Several short and long pressure transient tests for vertical and horizontal wells were conducted for Middle Bakken, Scallion, and Three Forks reservoirs. The bilinear, linear, and radial flow regimes of the pressure buildup tests were the focus of the analyses. The closed-form analytical solutions were provided to determine formation properties.
6.3.1 Description of Pressure Buildup Test

The field tests include pressure buildup tests of un-stimulated and stimulated horizontal wells as well as a pressure buildup for a vertical well in the Bakken Formation. **Downhole pressure gauges** were used to record pressure transient data in order to minimize wellbore storage effects during the buildup tests. The flowing pressure history, prior to the pressure buildup tests, were calculated from surface pressures. The drawdown and pressure buildup responses were then used to determine formation permeability.

For un-stimulated wells, the wells were open to production for several days right after drilling. The pressure buildup was conducted before the hydraulic stimulation, whereas for stimulated wells, they were produced for 1 to 2 years before performing the pressure buildup tests.

6.3.2 Pressure Buildup Interpretation

Mathematical models for horizontal well test analysis began to develop during the 1980’s, which provide solutions for a horizontal well located within an infinite slab reservoir. The characteristics of a pressure transient response in conventional horizontal wells include three basic flow regimes: early radial flow, intermediate-time linear flow, and late-time pseudo-radial flow (Ozkan et al., 1989). Larsen and Hegre (1994) suggested at least four fundamental flow periods for horizontal wells with a transverse or longitudinal fracture. In analyses of many Bakken wells, Kurtoglu et al. (2012b) concluded that the pressure transient responses of the long horizontal wells do not exhibit all flow regimes, only the bilinear and linear flow regimes were observed.

The theory and mathematical formulation of the numerical and analytical well testing solutions for unsteady state dual-porosity flow toward a horizontal well in unconventional reservoirs was developed by Torcuk et al. (2013) (see Chapter 7). This analytical model by Torcuk et al. (2013) was used to test a typical Bakken horizontal well in a naturally fractured reservoir (Kurtoglu et al., 2012b). **Figure 6.24** shows the input data for the analytical model and the resulting pressure and pressure derivative profiles.

In **Figure 6.24**, the early time linear flow regime represents linear flow for the fracture system alone. The intermediate time bilinear flow regime behavior represents the interaction between fractures and matrix. The long-time linear regime segment represents the total system (i.e. matrix and fractures) linear flow behavior.

In an attempt to explain the flow regimes observed in pressure buildups from several horizontal and vertical Bakken wells, the closed-form analytical solutions for each flow regime including bilinear, linear, and radial flow are presented. This allows one to analyze field well test data by applying the proposed pressure solutions to determine permeability. In this approach, the reservoir is assumed to be
isotropic and the reservoir fluid is slightly compressible with constant compressibility and viscosity throughout a constant reservoir thickness. In the following section, each flow regime is explained for a vertical well and un-stimulated and stimulated horizontal well.

![Figure 6.24: Input data for the analytical model and pressure and pressure derivative profiles for the unsteady-state transfer function analytical model.](image)

**Bilinear Flow**

Bilinear flow is a known phenomenon in finite-conductivity hydraulic fractures. It also can appear in the early the transient flow period of a horizontal well as a result of multi-layer permeability contrasts (Baba, et al., 2002). Similarly, bilinear flow appears in the transient flow period of horizontal wells in low-permeability dual-porosity reservoirs, which is the focus of this research.

**Bilinear flow in a vertical fractured well** occurs due to linear flow from the reservoir to the hydraulic fracture and another linear flow within the hydraulic fracture to the wellbore. Because the flow regime is controlled by the hydraulic fracture, the analysis of the bilinear flow regime observed in a fractured vertical well provides hydraulic fracture conductivity.

The equations for bilinear flow in a vertical fractured well follow:

\[
\Delta p = \frac{44.102 q B \mu}{h} \left( \frac{1}{k_{bf} w_{bf}} \right)^{1/2} \left( \frac{1}{(\phi \mu \lambda \omega)_{f+m} k_{f, eff}} \right)^{1/4} \]  

[6.20]

For pressure buildup analysis, superposition of time is applied to Eq. 6.20:
\[
\Delta p_{\text{wx}} = \frac{44.102 q B \mu}{h} \left( \frac{1}{k_{\text{hf}} w_{\text{hf}}} \right)^{1/2} \left( \frac{1}{(\phi \mu \alpha_i)_{f+m} k_{f,\text{eff}}} \right)^{1/4} \left( \frac{1}{\sqrt{h}} \right) \left( \frac{1}{\sqrt{t_1 + \Delta t}} \right) - \frac{1}{\sqrt{\Delta t}} \]  

[6.21]

Eq. 6.20 implies that a Cartesian plot of \( \Delta p \) versus \( t^{1/4} \) will yield a straight line with slope, \( m_{1/4} \):

\[
m_{1/4} = \frac{44.102 q B \mu}{h} \left( \frac{k_{f,\text{eff}}}{k_{\text{hf}} w_{\text{hf}}} \right)^{1/2} \left( \frac{1}{(\phi \mu \alpha_i)_{f+m} k_{f,\text{eff}}} \right)^{1/4} \]  

[6.22]

The above expression can be solved for the hydraulic fracture conductivity assuming the system permeability:

\[
k_{\text{hf}} w_{\text{hf}} = \frac{1944.96 \left( \frac{q B \mu}{h m_{1/4}} \right)^2}{\sqrt{(\phi \mu \alpha_i)_{f+m} k_{f,\text{eff}}}} \]  

[6.23]

**Bilinear flow in an un-stimulated horizontal well in a dual-porosity reservoir** occurs due to the synergy of the natural fracture flow toward the horizontal well and the matrix flow toward the fractures as illustrated in Fig. 6.25.

![Figure 6.25](image)

**Figure 6.25:** Idealization of bilinear flow in un-stimulated dual-porosity reservoirs.

In this case the derived permeability represents the total system of matrix and fractures in the reservoir. However, due to ultra-low matrix permeability in the Bakken Formation, pre-stimulation production is mostly driven by the micro-fractures in the reservoir. Thus, the analysis of bilinear flow before stimulation represents the effective fracture permeability in the reservoir.

The closed-form solution of the bilinear flow regime in a dual-porosity reservoir for an un-stimulated horizontal well was derived (Eq. 6.24) based on an early work by Du and Stewart (1992):
\[
\Delta p = \frac{45.103qB\mu}{\sqrt{k_{f,\text{eff}} hL}} \left( \frac{1}{1-\omega} \right)^{1/2} \frac{1}{\left[ \frac{\sigma}{4} k_m (\phi \mu \sigma)_{f+m} \right]^{1/4}} t^{1/4}
\]  

For buildup analysis pressure, the pressure equation takes the following form:

\[
\Delta p_{\text{wx}} = \frac{45.103qB\mu}{\sqrt{k_{f,\text{eff}} hL}} \left( \frac{1}{1-\omega} \right)^{1/2} \frac{1}{\left[ \frac{\sigma}{4} k_m (\phi \mu \sigma)_{f+m} \right]^{1/4}} \left( t_p + \Delta t - 4\sqrt{\Delta t} \right)
\]

Eq. 6.24 implies that a Cartesian plot of \(\Delta p\) versus \(t^{1/4}\) will yield a straight line with slope \(m_{1/4}\) providing that production time \(t_p\) is much larger compared to the pressure buildup time \(\Delta t\). The slope is:

\[
m_{1/4} = \frac{45.103qB\mu}{\sqrt{k_{f,\text{eff}} hL}} \left( \frac{1}{1-\omega} \right)^{1/2} \frac{1}{\left[ \frac{\sigma}{4} k_m (\phi \mu \sigma)_{f+m} \right]^{1/4}}
\]

The above equation is solved for the effective fracture permeability as shown below:

\[
k_{f,\text{eff}} = \left[ \frac{45.103qB\mu}{m_{1/4} hL} \right]^2 \left( \frac{1}{1-\omega} \right)^{1/2} \left[ \frac{\sigma}{4} k_m (\phi \mu \sigma)_{f+m} \right]^{1/2}
\]

The diagnostic log-log plot of pressure derivative vs. time displays a quarter slope (1/4 slope) for bilinear flow while the same data yields a straight line on the Cartesian plot of \(\Delta p_{\text{wx}}\) vs. \(t^{1/4}\).

**Bilinear flow in a stimulated horizontal well in a dual-porosity reservoir** occurs because of a combination of the linear flow in the hydraulic fracture and horizontal linear flow in the naturally fractured media toward the well as shown in Fig. 6.26. In this case the derived permeability represents the combination of hydraulic fractures, natural fractures, and matrix.
Linear Flow

Linear flow regime for the horizontal well-test data is described as the convergence of flow in the horizontal plane and occurs if the horizontal well is long enough (Ozkan, 1999). In the study of Larsen and Hegre (1994), the formation linear flow period for a horizontal well intersected by a longitudinal fracture and a transverse fracture is shown to be identical. Additionally, for a multifractured horizontal well the compound-formation linear flow period is characterized by linear flow from the formation to the collection of fractures and finally to the wellbore.

Linear flow in a stimulated vertical well occurs in the normal direction of the fracture plane. Linear flow regime is observed as a half slope on a log-log plot of pressure derivative vs. time. The Cartesian plot of $\Delta p$ versus $t$ is governed by the following equation:

$$
\Delta p = \frac{4.064}{hx_f} \left( \frac{1}{(\phi \mu c_i)_{f+m} k_{f,eff}} \right)^{1/2} \sqrt{t} + \Delta p_{x,bf}
$$

[6.28]

For pressure buildup analysis superposition of time is applied to Eq. 6.28, which results in Eq. 6.29.

$$
\Delta p_{wr} = \frac{4.064}{hx_f} \left( \frac{1}{(\phi \mu c_i)_{f+m} k_{f,eff}} \right)^{1/2} \left( \sqrt{t_p} + \Delta t - \sqrt{\Delta t} \right)
$$

[6.29]

Eq. 6.28 implies that a Cartesian plot of $\Delta p$ versus $t^{1/2}$ will yield a straight line with slope, $m_{1/2}$:

$$
m_{1/2} = \frac{4.064}{hx_f} \left( \frac{1}{(\phi \mu c_i)_{f+m} k_{f,eff}} \right)^{1/2}
$$

[6.30]
Eq. 6.30 can then be solved for the effective permeability:

\[
k_{f,\text{eff}} = \left(\frac{4.064}{m_{1/2}h x_f}\right)^2 \left(\frac{1}{(\varphi \mu c)_{f+m}}\right) \quad [6.31]
\]

**Linear flow in an un-stimulated horizontal well in a dual-porosity reservoir** may occur due to the flow in natural fractures enhanced by the matrix flow in the reservoir. The flow will be linear in the normal direction of the well axis. The derived permeability represents the total system including matrix and fracture.

This flow regime can be analyzed by replacing fracture half-length \(x_f\) in Eq. 6.30 with horizontal half-length \(L/2\) which results in Eq. 6.32.

\[
\Delta p = \frac{8.128}{h L} \left(\frac{1}{(\varphi \mu c)_{f+m} k_{f,\text{eff}}}\right)^{1/2} \sqrt{t} + \Delta p_{\text{s,unbw}} \quad [6.32]
\]

For pressure buildup analysis, superposition of time is applied to Eq. 6.33:

\[
\frac{\Delta p_{\text{ws}}}{h L} = \frac{8.128}{h L} \left(\frac{1}{(\varphi \mu c)_{f+m} k_{f,\text{eff}}}\right)^{1/2} \left(\sqrt{t_p + \Delta t} - \sqrt{\Delta t}\right) \quad [6.33]
\]

Eq. 6.32 implies that a Cartesian plot of \(\Delta p\) versus \(t^{1/2}\) yields a straight line with a slope of \(m_{1/2}\):

\[
m_{1/2} = \frac{8.128}{h L} \left(\frac{1}{(\varphi \mu c)_{f+m} k_{f,\text{eff}}}\right)^{1/2} \quad [6.34]
\]

The above equation can then be solved for the effective permeability:

\[
k_{f,\text{eff}} = \left(\frac{8.128}{m_{1/2}h L}\right)^2 \left(\frac{1}{(\varphi \mu c)_{f+m}}\right) \quad [6.35]
\]
Linear flow in a stimulated horizontal well in a dual-porosity reservoir is the same as described for the un-stimulated horizontal wells governed by Eq. 6.32 through 6.35. However, the estimated permeability in this case represents the enhanced stimulated reservoir volume permeability (Fig. 6.27).

**Figure 6.27:** Idealization of linear flow in hydraulically fractured stimulated dual-porosity reservoirs.

**Radial Flow**

For any well geometry, at late times prior to the influences of the boundaries, a radial flow regime may develop. However, due to ultra-low permeability in the Bakken Formation, observing a radial flow from a long horizontal multi-stage well is not expected within the economic time of test duration.

Radial flow in a vertical well is developed when the flow convergence toward the well is radial and the well is assumed to be fully penetrating. Radial flow in stimulated horizontal well can be developed both at early and late times depending on the reservoir permeability. In a low-permeability reservoir, reaching this late radial flow is not observed due to long transient flow. At early-time, flow is radial in the vertical plane normal to the well axis thorough a fracture. In the late time, flow convergence is predominantly radial away from the well. Radial flow convergence occurs from the reservoir to the wellbore. The pressure equation with its slope and permeability definitions is provided from Eq. 6.1 to 6.4.

**6.3.3 Pressure Buildup Field Applications**

This section presents four field examples that were analyzed using the mathematical models presented in Section 6.3.2. The examples include an un-stimulated horizontal well (Middle Bakken), a single-stage horizontal well (Middle Bakken), a stimulated vertical well (Three Forks), and a multi-stage horizontal well (Scallion). More examples were provided in Kurtoglu et al. study (2012b).
Field Example -1

Example 1 is a 9123-ft un-stimulated horizontal well in the Middle Bakken Formation in Bailey Field. After ten days of initial production, the well was shut in for three days for a pressure buildup test. The average oil production rate prior to stimulation was 125 bbl/d.

Figure 6.28 shows the well pressure, rate history, the log-log pressure, and pressure derivative plot. The wellbore storage dominates only the early time of the pressure transient response with a unit slope, followed by a bilinear flow of a quarter slope.

Figure 6.28: Example 1: (a) Pressure and flowrate history, (b) pressure and pressure derivative plot.

The matrix permeability was assumed to be the measured core permeability, while the shape factor (indication for the fracture intensity) was calculated based on the knowledge of fracture spacing in un-stimulated Bakken Formation. Next, the bilinear flow equation, Eq. 6.27, was used to estimate effective fracture permeability. The bilinear flow is shown by the blue line in Fig. 6.28b. This data was analyzed using the bilinear flow plot in Fig. 6.29.

Figure 6.29: Example 1: Bilinear flow plot and bilinear flow solution.
The calculated effective fracture permeability is 0.0009 md assuming the full length contributing to the production. Thus, this represents the lowest estimation of the effective permeability (microfractures and matrix).

The analysis of the bilinear flow regime requires independent reservoir data (such as matrix permeability, fracture porosity, fracture intensity). This analysis provides the effective permeability of the reservoir before stimulation which indicates the long-term production capability of the reservoir. These results are beneficial to reservoir management and economic decisions.

**Field Example -2**

Example 2 is a 9392-ft horizontal well in the Middle Bakken Formation with a single-stage completion in Bailey Field. After two months of production following the hydraulic fracture treatment, the well was shut in for three days for a pressure buildup test.

**Figure 6.30** shows the well pressure, rate history, and the log-log pressure, and pressure derivative responses. The log-log plot suggests that the wellbore storage effect was insignificant. The pressure transient response was dominated by linear flow.

![Figure 6.30: Example 2: (a) Pressure and flowrate history, (b) pressure and pressure derivative plot](image)

The closed-form solution for the linear flow regime, Eq. 6.35, was used to calculate the effective fracture permeability. The linear flow plot and the results are summarized in **Fig. 6.31**. A formation effective permeability, $k_{eff}$, of 0.022 md was estimated assuming 20% of the well length contributing to the production, and 0.001 md using the full length.

The Middle Bakken effective permeability derived from this pressure buildup agrees well with the result obtained by mini-DST (Section 6.1.4) and mini-frac test (Section 6.2.3) of Example 1.
Field Example -3

Example 3 is a pressure buildup test conducted in a stimulated vertical well in the Three Forks Formation in Reunion Bay. After thirty days of production the well was shut in for three days for a pressure buildup. The average rate of oil production was 22 bbl/d.

Figure 6.32 shows the well history, the log-log pressure, and pressure derivative responses. In the log-log plot the main flow regime has linear flow characteristic (1/2 slope) as expected for a stimulated vertical well.

The linear portion of the pressure derivative was further analyzed using the closed-form equation, Eq. 6.31. Since there are two unknowns to solve including fracture half length ($x_f$) and effective permeability ($k_{f,eff}$), two solutions were provided to identify the range of expected fracture half-lengths of a vertical well (80 and 160 ft) in Fig. 6.33. A thorough understanding of the range of permeability and fracture half-lengths are important when modeling the hydraulic fractures in the reservoir model (Chapter 8).
The solution method of the linear flow regime is the most reliable because (1) it covers a long period of production and (2) it requires the least amount of auxiliary data (such as porosity) to calculate the effective fracture permeability. This permeability can be used to forecast a long-term performance of the test well.

In summary, the bilinear flow regime observed for un-stimulated horizontal wells provides insights into fracture characterization while linear flow regimes observed for fractured horizontal wells shows the importance of completion and stimulation to enhance oil production by creating more flow paths to the wellbore. The bilinear regime solution is a less reliable method; it requires more auxiliary data, such as matrix permeability and fracture spacing. Nonetheless, the bilinear regime solution can provide a preliminary estimate of effective fracture permeability.

**Pressure Buildup Field Example -4**

Example 4 is an 8628-ft, 30-stage stimulated horizontal well in the Scallion Formation in East Bailey Field. After two days of initial production the well was shut in twelve days for a pressure buildup test. The average oil production rate prior to stimulation was 200 bbl/d. This is the identical well for which mini-DST (Section 6.1.4) and mini-frac tests (Section 6.2.3) were presented in Example 2. In summary, the calculated permeability of the Scallion well was higher than that of the Middle Bakken well based on the mini-DST. In the mini-frac of the Scallion well, the pressure dependent leak off mechanism with early fracture closure was obtained.

**Figure 6.34** shows the well history, the log-log pressure, and pressure derivative plot. Wellbore storage dominates only early pressure transient response (until 0.1 hr) with a unit slope followed by a radial flow of a zero slope (between 1 and 10 hr). The late part is deviating towards linear flow with a slope of $\frac{1}{2}$. 

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<tbody>
<tr>
<td>$\mu$</td>
<td>0.28 cp</td>
</tr>
<tr>
<td>$B$</td>
<td>1.48 RB/STB</td>
</tr>
<tr>
<td>$c_t$</td>
<td>1.64E-05 psi$^{-1}$</td>
</tr>
<tr>
<td>$h$</td>
<td>52 ft</td>
</tr>
<tr>
<td>$\varphi$</td>
<td>0.05</td>
</tr>
<tr>
<td>$q_{avg}$</td>
<td>22 BBL/D</td>
</tr>
<tr>
<td>$m_{1/2}$</td>
<td>115 psi/hr$^{1/2}$</td>
</tr>
<tr>
<td>$x_{f1}$</td>
<td>80 ft</td>
</tr>
<tr>
<td>$x_{f2}$</td>
<td>160 ft</td>
</tr>
<tr>
<td>$k_{f,eff1}$</td>
<td>0.022 md</td>
</tr>
<tr>
<td>$k_{f,eff2}$</td>
<td>0.005 md</td>
</tr>
</tbody>
</table>

**Analytical Solution: Stimulated Vertical Well**
The radial portion of the pressure derivative was further analyzed using the radial flow equation, Eq. 6.3. Because this well had a 30-stage completion some assumptions were made to calculate the effective permeability. Each fracture was assumed to contribute to the production equally which resulted in 6.66 bbl/d per stage. Each fracture was treated individually as a fractured vertical well. In this case, radial flow was developed along the fracture while the well was assumed to be fully penetrating. The thickness was transformed into horizontal length around a single fracture (total well length/number of stages = 288 ft). The calculated effective permeability is 0.004 md. If 20% of full-length contribution is assumed the effective permeability is 0.022 md.

**Figure 6.35:** Example 4: Semi-log plot and the results from radial flow solution.

**Figure 6.36** summarizes the test results for both Middle Bakken and Scallion formations. The following summarize the observations:

- The mini-DST results show that during thirty minutes of drawdown, the Scallion Formation produced more reservoir fluid (4028 cc) than that of the Middle Bakken (2562 cc). This indicates the higher flow capacity in the Scallion results in stabilized pressure at the end of the buildup.
**Figure 6.36:** Summary of well test and well production results for the Middle Bakken and Scallion formations.

- The mini-frac test from the Middle Bakken Formation exhibits a transverse storage leakoff mechanism while the Scallion has a pressure dependent leakoff with a lower pore pressure.
- The pressure transient response from a long-pressure buildup for a multi-stage Scallion well exhibits a radial flow whereas the flow regime from a Middle Bakken multi-stage well stays in linear flow.
- Oil production started with a high initial rate in the Scallion well but dropped rapidly. In the Middle Bakken well, steady oil flow rate was observed for a long time. With the same well
completion, the Scallion well produced 20,000 STB of oil in 300 days and the Middle Bakken well produced 20,000 STB in 26 days.

All these information are indicative of a more fractured system in the Scallion Formation. In contrast to the greater flow capacity in the Scallion, the scenario changed when the Scallion well started to produce due to high intensity pressure-dependent fractures. The Scallion Formation is thinner (13 ft) than that of the Middle Bakken (51 ft). Therefore, despite the fact that the Scallion Formation has a greater permeability to start with, its petrophysical properties (summarized in Chapter 3) and its fracture properties limit the long-term sustainable production.

In order to economically develop the Scallion Formation, a small number multi-stage completion drilling a short horizontal well or drilling a vertical well may be a better option than drilling a 30-stage long horizontal well.
CHAPTER 7

RATE TRANSIENT ANALYSIS

In unconventional reservoirs flow rate changes with time rapidly and is hard to maintain at a constant rate. Initially unconventional reservoirs produce at a high flow rate upon hydraulic fracturing and continue to decrease through well life. This exhibits a hyperbolic decline rather than an exponential decline behavior as in conventional reservoirs. From the early development of the Bakken Formation, there are several key drivers impacting well production including well configuration, well completion and stimulation, and geology. This chapter addresses the impact of those key production drivers on decline behavior, flow capacity, and flow regime characteristics of the pressure-time signature. The methodologies to analyze pressure and rate data are presented with field examples.

In this study, although we focus on the Bakken in North Dakota, analyzing Bakken production performance in Elm Coulee Field in Montano was critical due to its longer production history. The objective was to develop a better understanding of how to predict the long-term performance of younger Bakken fields in North Dakota based on the Elm Coulee production experience.

7.1 Key Production Drivers in the Bakken

Predicting performance of wells from ultra-tight unconventional reservoirs has historically been challenging due to their unique flow characteristics in comparison to typical conventional reservoirs. The main difference is the long-transient flow period occurring in ultra-low permeability reservoirs. In addition, the complexities of geology and the advancements in completion and stimulation technology make the interpretation of the long-transient flow regime even more challenging because of the numerous flow paths in the reservoir. This section summarizes the completion chronology in Bakken and the geologic differences between the Bakken in North Dakota and Montano to provide insights about the key production drivers.

7.1.1 Well Completion Technology

The first discovery of the Bakken Formation in the Williston Basin occurred in the Antelope Field in 1953 and the development of the field began soon after. The development continued into the 1960’s with vertical wells producing from the Middle Bakken and Upper Three Forks formations.

The second period of vertical well development, using a single-stage axial hydraulic fracture, occurred in the Upper Bakken Shale Formation around the Billings Anticline between 1970 and 1985. The first horizontal well drilling in the Upper Bakken Shale commenced in 1987. The horizontal wells
typically consisted of pre-perforated liner completion, often incorporating diversion materials in an attempt to generate multiple zones of stimulation (Pearson et al., 2013). In these completions, low rate, high viscosity fracture fluid (cross-linked gel) was injected into an un-cemented wellbore. The objective was to activate pre-existing natural fractures and create longitudinal axial fractures along the wellbore.

The status changed in 2000 with the discovery of significant reserves in the Middle Bakken of the Elm Coulee Field (Sonnenberg, 2009). Horizontal wells, with a single-stage cemented completion, were utilized in the early developments of Elm Coulee Field. Well completions were then altered from cemented to un-cemented liners which resulted in significant productivity increases in Elm Coulee Bakken compared to previous completion techniques.

In 2006 the development of the Middle Bakken of Elm Coulee Field led to the exploration of other fields in the Williston Basin, starting with Parshall and Sanish fields in North Dakota (see Fig. 3.2). After the success of the first multi-stage well with transverse hydraulic fractures in Parshall Field in 2007, multi-stage fracture technology was deployed in other fields in the Williston Basin.

Multi-stage completions include plug-and-perf (cemented liner), sliding sleeve (open-hole swellable packer), and a hybrid method. Plug-and-perf technology involves cementing the production casing in the horizontal wellbore. Stage-to-stage isolation in the liner is accomplished by setting bridge plugs, followed by perforating and then fracturing the well at each stage (Appleton and Rivenbark, 2013). In the swellable packer multi-stage system the horizontal wellbore is left as an open hole. The packers are set to isolate sections of the wellbore into individual stages. Stimulation ports are run between packers, which can be opened hydraulically. The major advantage of the sliding sleeve system is that all stage treatments can be performed in a single continuous operation, saving time and cost. In both completion methods, slickwater is the preferred fracturing fluid because its low viscosity is suitable for higher flow rates for creating an extensive micro-fracture network.

The earliest wells in the study area (Murphy Creek, Bailey, and Reunion Bay fields) are primarily open-hole, single stage, un-cemented liner completions (500,000 lb of sand with 750,000 gallons of cross linked-gel). Wells drilled in the intermediate development period of the field are generally multi-stage wells comprising 8 to 10 hydraulic fracture stages with a mixture of plug-and-perf and sliding sleeve systems (i.e., swellable packer). As these fields are being developed, the number of stages has steadily increased to as high as 30 stages and a swellable-packer completion has been commonly used since 2012, typically using 2,000,000 lb of sand per 1,000,000 gallons of a hybrid fracturing fluid.
7.1.2 Bakken Formation Geology Comparison

The petrophysical differences between the Bakken in North Dakota (Fig. 3.4) and the Bakken in Elm Coulee Field (Fig. 3.5) were presented in Chapter 3. In this section, both geologic and reservoir differences are compared between those Bakken reservoirs. Table 7.1 compares lithology, thickness, depositional model, lithofacies, porosity, matrix permeability, water saturation, fracture intensity, resistivity, pressure gradient, reservoir temperature, and average well length between these Bakken reservoirs.

Table 7.1: Comparison of geologic and reservoir properties of Elm Coulee Field, Montana, and properties of Murphy Creek, Bailey and Reunion fields, North Dakota

<table>
<thead>
<tr>
<th>Properties</th>
<th>Montana</th>
<th>North Dakota</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Elm Coulee Field</td>
<td>Murphy Creek, Bailey and Reunion Bay Fields</td>
</tr>
<tr>
<td>Lithology</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upper Bakken</td>
<td>organic-rich shales</td>
<td>organic-rich shales</td>
</tr>
<tr>
<td>Middle Bakken</td>
<td>silty dolostone</td>
<td>limestone to sandstone</td>
</tr>
<tr>
<td>Lower Bakken</td>
<td>organic-rich siltstone</td>
<td>organic-rich shales</td>
</tr>
<tr>
<td>Unit Thickness (ft)</td>
<td>6 - 10</td>
<td>12 - 18</td>
</tr>
<tr>
<td>Upper Bakken</td>
<td>10 - 40</td>
<td>30 - 40</td>
</tr>
<tr>
<td>Middle Bakken</td>
<td>2 - 6</td>
<td>8 - 10</td>
</tr>
<tr>
<td>Depositional Model</td>
<td>Dolomitized carbonate-shoal off-shore marine carbonate-shoal complex</td>
<td>Marine swamp with restricted circulation</td>
</tr>
<tr>
<td>Middle Bakken Facies</td>
<td>Laminated dolostone (MB3), bioturbated dolostone (MB4), interbedded lower grainstone (MB5)</td>
<td>Dolomitic lime mudstone (MB1), packstone (MB2), laminated sandstone and siltstone (MB3), bioturbated sandstone and siltstone (MB4), lower grainstone (MB5)</td>
</tr>
<tr>
<td>Middle Bakken Porosity (%)</td>
<td>5 - 7</td>
<td>4 - 6</td>
</tr>
<tr>
<td>Porosity Type</td>
<td>Intercrystalline secondary porosity due to dolomitization</td>
<td>Intergranular porosity, intragranular within clay filled pore volume</td>
</tr>
<tr>
<td>Core Permeability (md)</td>
<td>0.01 - 0.1</td>
<td>0.0001-0.001</td>
</tr>
<tr>
<td>Water Saturation</td>
<td>25</td>
<td>50</td>
</tr>
<tr>
<td>Prominent Structural Features</td>
<td>Poplar Dome</td>
<td>Nesson and Billing Anticline</td>
</tr>
<tr>
<td>Pressure Gradient (psi/ft)</td>
<td>0.53</td>
<td>0.78</td>
</tr>
<tr>
<td>Reservoir Temperature (*F)</td>
<td>240</td>
<td>240</td>
</tr>
<tr>
<td>Oil Density (API)</td>
<td>42</td>
<td>39 -42</td>
</tr>
<tr>
<td>HW Drilling Starts (MB)</td>
<td>2000</td>
<td>2006</td>
</tr>
<tr>
<td>Average Well Length (ft)</td>
<td>5000</td>
<td>9000</td>
</tr>
</tbody>
</table>
The key reservoir parameters differ between the Bakken in Elm Coulee Field and the Bakken in North Dakota fields. The Bakken in Elm Coulee has an order of magnitude higher matrix permeability, higher fracture intensity, lower initial reservoir pressure, higher oil saturation, and higher porosity due to dolomitization than the Bakken in North Dakota. Therefore, both primary depletion and any EOR application would perform differently. In this chapter, several Elm Coulee wells will be presented in comparison to North Dakota Bakken wells.

7.2 Methodology and Field Examples
Numerous empirical and analytical methods have been used to investigate the short- and long-term reservoir behaviors of unconventional reservoirs. This includes traditional decline-curve analysis (Arps, 1945), power-law exponential method (Ilk et al, 2008), stretched-exponential method (Valko, 2010), rate-decline method (Duong, 2011), and transient productivity index analysis (Medeiros et al, 2010). Because each methodology has different assumptions and newer wells have a short production history, reliable forecasting on future performance is questionable.

To analyze the effects of geology and completion techniques on well productivity and well flow regimes, the following techniques are discussed including (1) rate versus time plot, (2) rate versus cumulative production plot, (3) Cartesian plot of normalized pressure versus square root of time plot, (4) log-log plot of normalized pressure and rate versus material balance time, and (5) log-log plot of normalized pressure and pressure derivative versus material balance time plot. The use of these techniques is illustrated using the field examples of Montana Elm Coulee and North Dakota.

7.2.1 Rate versus Time Plot --Decline Curve Analysis
Arps decline curve analysis has been extensively used to estimate reserves from depletion drive oil and gas reservoirs since 1950’s. The method utilizes the following hyperbolic rate equation, Eq. 7.1:

\[ q(t) = q_i (1 + bD_D t)^{-1/b} \]  

Where \( q \) is the flow rate, \( D \) is the decline rate, Eq. 7.2,

\[ D = -d \ln q/dt \]  

and \( b \) is the decline exponent which is the time derivative of the reciprocal of the decline rate, Eq. 7.3.
\[ b = \frac{d(1/D)}{dt} = -\frac{d}{dt}\left(\frac{q}{dq/dt}\right) \]  

For hyperbolic decline, \(0 < b < 1\), for exponential decline \(b = 0\), and for harmonic decline \(b = 1\). It has been shown that forecasting using a constant \(b\), obtained from the early transient flow, overpredicts the well performance for wells that have long transient flow periods. To match the long-term performance of Elm Coulee wells, the numerical value of \(b\) had to be decreased with increasing time. A theoretical reason to support of this behavior can be explained by the analytical numerical solution of a capacitance model (Yousef et al., 2006)

The capacitance model infers interwell connectivity from well rate data. This method works effectively for conventional reservoirs with high connectivity. The flow rate is defined as follows:

\[ q(t) = J(\bar{p} - p_w) \]  

\[ -q(t) = \varphi c_i V_R \frac{\partial \bar{p}}{\partial t} \]  

Where \(q(t)\) is production rate, \(J\) productivity or well index, \(\bar{p}\) average pressure in the drainage volume of the well, \(p_w\) bottom-hole well pressure, \(V_R\) drainage volume of the well, \(\varphi c_i\) specific storage coefficient, and \(t\) time. For an analytical solution to the capacitance model, \(J\) and \(V_R\) are assumed constant while \(p_w\) can be either constant or varying with time.

When bottom-hole pressure is variable the solution involves a convolution integral. This solution can be used to explain why flowrate can increase with decreasing the bottom-hole pressure. This method can also be used in low permeability depletion-type of unconventional reservoirs. The equations below explain why the hyperbolic decline exponent does not remain constant and why it decreases with time.

\[ q(t) = q(t_w) e^{\frac{(t-t_w)}{\tau}} \]  

Where

\[ \tau = \varphi c_i V_R / J \]
For constant $J$, $V_R$, and $p_w$, the solution of Eq. 7.6 and Eq. 7.7 is the exponential decline of flowrate versus time. Taking logarithm of Eq. 7.6 leads to a straight line with a slope of $-1/\tau$, which is the same as the exponential decline rate, $D$, in the conventional nomenclature of decline curve analysis (Ilk, et al, 2008). The conventional decline exponent $b$ is defined below:

$$b = \frac{d}{dt}(1/D) = \frac{d}{dt}(\varphi c_i V_R / J)$$  \[7.8\]

In high-permeability conventional reservoirs, when $V_R$, $J$, and $\varphi c_i$ are constant, i.e $\varphi c_i V_R / J$ is not a function of time, $b$ becomes zero. This is consistent with the definition of exponential decline.

In low-permeability unconventional reservoirs, the variation of $V_R$ and $J$ vary is less pronounced than in high-permeability reservoirs. In other words, both the drainage volume term, $\varphi c_i V_R$, and well index, $J$, vary with time at different rates. In fact, drainage volume contribution grows slower than the well index as time increases. Thus, while $b$ versus time is a positive function with a positive slope, its slope will decrease with time due to lack of reservoir connectivity. The decrease in slope $b$ can be considered as a measurement of reservoir heterogeneity, loss of pore volume connectivity (reservoir production conformance) and/or pore volume compartmentalization away from the wellbore.

The Arps empirical rate-decline equation does not capture the decreasing trend of $b$ during transient flow period, its reserve estimation becomes questionable. A study by Rushing et al. (2007) shows the errors in estimating reserves using a hyperbolic decline with constant $b$ values. This issue was also addressed by Ilk et al. (2008) recognizing the common practice of using constant $b$ over the well life is needed to prevent from forecasting unrealistic reserves.

Rushing et al. (2007) used the terminal decline concept so that the hyperbolic curve generated by using a constant $b$ value would be limited by changing the hyperbolic relation to exponential when the decline rate reaches the pre-defined terminal rate, $D_{\text{min}}$. The main concern of this method is an estimation of $b$ value for transient flow regime and terminal decline rate. This creates inconsistent reserve estimations with high uncertainty due to pre-defined parameters. To resolve this issue the Arps standard decline rate equation was applied until $D$ reaches $D_{\text{min}}$ thereafter, the exponential decline equation with the decline exponent equal to $D_{\text{min}}$ was then used.
Figure 7.1 illustrates the sensitivity of $b$ values and terminal decline rate, $D_{\text{min}}$, on production. Furthermore, the figure shows a range of uncertainty in the estimated ultimate recovery (EUR) especially early in the well life. As $b$ increases, the EUR values increase as shown on the figure for terminal decline rates of 4 to 10% per year. Further investigation related to the range of terminal decline rate for the Bakken in North Dakota was provided by Kurtoglu et al. (2010).

![Figure 7.1: Arps hyperbolic decline analysis until D reaches $D_{\text{min}}$, after which the exponential decline with $D_{\text{min}}$ used.](image)

To illustrate the change in $b$ values during transient flow regime, a production from Elm Coulee well was divided into 12, 48, and 72 months. Decline curve analysis was then applied to each subset of data starting from the initial production to estimate ultimate recovery (Fig. 7.2). As noted, $b$ decreases with increasing time which results in lower reserves estimates.

To demonstrate the dependence of well completion methods on rate-time behavior, the Arps flow rate exponent $b$ for 688-Elm Coulee wells was calculated using Eq. 7.3. The wells were completed from 1998 to 2012 with various completion techniques. The objective was to visualize the evolution of the completion technology and decline factor. Figure 7.3 plots those Arps flow rate exponent $b$ against the completion year for Elm Coulee wells. The increasing Arps flow rate exponent $b$ with completion year may be attributed to an increase of reservoir connectivity as a result of improved completion technology culminating with the multi-stage method. The average of Arps flow rate exponent $b$ for the entire dataset
is around 1.3 and increasing up to 1.6 with multi-stage completion wells in 2007. As mentioned in Section 7.1.1, multi-stage completion started to deploy in 2007 in Bakken.

**Figure 7.2:** Changing $b$ exponent during the early transient flow in Arps hyperbolic decline rate equation.

**Figure 7.3:** Arps flow rate exponent $b$ for 688 wells in Elm Coulee Field as a function of completion date.
7.2.2 Oil Flow Rate versus Cumulative Oil Production Plot

Besides rate-time behavior, a rate versus cumulative analysis can be used as a diagnostic plot to observe decline behavior. This method is suitable for wells with long-history after early transient flow. To demonstrate this method several Bakken wells were selected including (1) a horizontal well from Elm Coulee Field, (2) a vertical well in West Tioga Field from the 1970’s, (3) a 1990’s horizontal well in Devil Pass Field near Nesson Anticline, and (4) three horizontal wells from Bailey Field. These wells represent the completion chronology discussed in Section 7.1.1. Table 7.2 summarizes the well completion and production information. Figure 7.4 plots oil rate versus cumulative production of these wells.

Table 7.2: Summary of well properties (VW: Vertical well, HW: Horizontal well, UBS: Upper Bakken Shale, MB: Middle Bakken)

<table>
<thead>
<tr>
<th>Well #</th>
<th>Well Type</th>
<th>Approximate Well Length</th>
<th>Field</th>
<th>Formation</th>
<th>Completion Stage</th>
<th>Days of Production</th>
<th>Cum. Oil MBBL (150 days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>VW</td>
<td>--</td>
<td>West Tiango</td>
<td>UBS</td>
<td>1-stage</td>
<td>10777</td>
<td>119</td>
</tr>
<tr>
<td>2</td>
<td>HW</td>
<td>2000</td>
<td>Devil Pass</td>
<td>UBS</td>
<td>1-stage</td>
<td>4869</td>
<td>95</td>
</tr>
<tr>
<td>3</td>
<td>HW</td>
<td>5000</td>
<td>Elm Coulee</td>
<td>MB</td>
<td>1-stage</td>
<td>2556</td>
<td>491</td>
</tr>
<tr>
<td>4</td>
<td>HW</td>
<td>9000</td>
<td>Bailey</td>
<td>MB</td>
<td>1-stage</td>
<td>1781</td>
<td>111</td>
</tr>
<tr>
<td>5</td>
<td>HW</td>
<td>9000</td>
<td>Bailey</td>
<td>MB</td>
<td>15-stage</td>
<td>1028</td>
<td>145</td>
</tr>
<tr>
<td>6</td>
<td>HW</td>
<td>9000</td>
<td>Bailey</td>
<td>MB</td>
<td>30-stage</td>
<td>146</td>
<td>60</td>
</tr>
</tbody>
</table>

Figure 7.4: Oil rate versus cumulative oil production for the selected Bakken wells.
Below is a summary of the well characteristics, behavior, and observations from the production plot of Fig. 7.4:

- Vertical Well 1 and horizontal Well 2 were completed in the Upper Bakken Shale. Although this formation has ultra-low permeability, these wells produced for over twenty years without today’s advanced completion and stimulation techniques. Even after thirty years, vertical Well 1 is still producing at a constant rate suggesting a persistent flow contribution from matrix.

- Increase in production was observed from vertical wells to short laterals, short laterals to long laterals, and single-stage completion to multi-stage completion.

- Well 3, a short lateral with a single-stage fracture, outperformed Well 5 and Well 6 that are long laterals with multi-stage fractures. This can be explained by the higher permeability, higher porosity, and higher fracture intensity of the Middle Bakken in Elm Coulee Field than those in North Dakota (Table 7.1).

7.2.3 Cartesian Plot of Normalized Pressure versus Square Root of Time

If bottom-hole flowing pressure data are available, the variable rate and the pressure data can be analyzed using several diagnostic methods. For the interest of rate transient analysis, linear flow is the focus of this chapter. This section illustrates the use of linear flow equations for both single- and multi-phase flow.

**Single-Phase Flow**

The closed-form solution of linear flow regime derived from the diffusivity equation for the single phase, slightly compressible flow in a dual-porosity media was given by Eq. 6.32. Equation 7.9 represents the same equation where time is in days instead of in hours:

\[
\frac{\Delta p(t)}{qB} = 8.128 \sqrt{24} \frac{\mu}{\sqrt{k_{f,eff}} hL} \left( \frac{1}{(\rho \mu \phi \gamma)} \right) \sqrt{t} \quad [7.9]
\]

Where the pressure is in psi, flowrate is in STB/D, permeability is in md, and viscosity is in centipoise. The slope of \(\Delta p\) versus \(t^{1/2}\) plot is used to estimate the effective permeability from linear flow period as follows:
\[
k_{f,\text{eff}} = \left( \frac{8.128\mu}{m_{v/2}hL} \right)^2 \frac{24}{(\phi \mu \kappa_{r})_{f+m}} 
\]

[7.10]

In Eq. 7.9 and 7.10, \( L \) represents horizontal well length, but additional pressure drop due to skin effect is not included. To analyze long-term production data for a fractured horizontal well, \( \frac{\Delta p}{q} \) versus square-root of time \( (t^{1/2}) \) plot is used. The linear flow equation including the skin effect for a slightly compressible, single phase flow at the hydraulic fracture face can be written as:

\[
\frac{\Delta p(t)}{qB} = 4.064\sqrt{24} \frac{\mu}{k_{f,\text{eff}}} \left( \frac{1}{(\phi \mu \kappa_{r})_{f+m}} \right)^{1/2} \sqrt{t} + 141.2 \frac{\mu}{k_{f,\text{eff}} h n_f} S_{hf} 
\]

[7.11]

Where \( y_f \) (in feet) is the fracture half-length for a single transverse hydraulic fracture in a multi-stage completion, and \( n_f \) is the total number stages of hydraulic fracture. This equation is also applicable to open-hole, multi-stage completion because flow is dominated by well flowing perpendicular to the hydraulic fracture. Eq. 7.11 takes the following form:

\[
\frac{p_t - p_{wf}}{qB} = m\sqrt{t} + b
\]

[7.12]

Where

\[
m_{v/2} = 4.064\sqrt{24} \frac{\mu}{k_{f,\text{eff}}} \left( \frac{1}{(\phi \mu \kappa_{r})_{f+m}} \right)^{1/2} ; \quad m = \left[ \frac{\text{psi}}{(RB/d) \sqrt{d}} \right]
\]

[7.13]

\[
b = 141.2 \frac{\mu}{k_{f,\text{eff}} h} S_{hf} ; \quad b = \left[ \frac{\text{psi}}{(RB/d) \sqrt{d}} \right]
\]

[7.14]

Effective permeability can be derived from Eq. 7.13 as follows:
Because the slope \( m_{ij2} \) has an inverse relation with \( k_{f,\text{eff}} \) (Eq. 7.15), the smaller the slope of the linear flow analysis the better the well productivity is. The term \( \sqrt{\frac{k_{f,\text{eff}}(hn_fy_f)}{m_{ij2}h_{n_f}y_f}} \) in Eq. 7.15 represents the effect of flow from both geology and completion differences. Identifying each parameter in this equation requires assumptions of net thickness \( h \), stage efficiency \( n_f \), fracture half-length \( y_f \), and permeability in the stimulated area \( k_{f,\text{eff}} \). However, a consistent approach applied to group of wells can help to identify better geological areas and best completion practices.

To demonstrate this approach completion and production data from 78 wells in Murphy Creek, Bailey, and Reunion Bay fields were analyzed to calculate effective permeability using Eq. 7.15. The selected wells had at least one year production history with various completion methods. It was assumed that the total length was contributing to the production. This analysis provided insights not only about the completion efficiency from single- to multi-stage completion but also about the impact of different rock and fluid properties on well productivity among the fields. Figure 7.5 shows the cumulative frequency plot of the calculated effective permeability for each field.

![Cumulative Frequency Plot](image)

**Figure 7.5:** Cumulative frequency plot of calculated effective permeability from linear flow analysis.

Below is a summary of the observations related to the completion, geology, and fluid properties from Fig. 7.5:

- Wells with multi-stage completions tend to have higher effective permeabilities. This indicates an increased flow capacity with multi-stage completion.
- Range of effective permeability distribution varies in each area: between 0.0001 md and 0.07 md for Murphy Creek Field, between 0.005 md and 0.09 md in Bailey Field, and between 0.01 md
and 0.2 md in Reunion Bay Field. This information reveals that Reunion Bay Field has the highest reservoir connectivity than Bailey and Murphy Creek. This was expected because Reunion Bay Field is closer to Nesson Anticline to the west (Fig. 3.2), and has the lowest viscosity, and the highest solution-GOR than those of Murphy Creek and Bailey fields (Table 5.1).

- In the determination of a CO₂ pilot location, Murphy Creek and Bailey areas were considered to be more preferable than Reunion Bay. This is because the increased effective permeability observed in Reunion Bay is mainly due to the fracture corridors and faults observed from seismic and curvature. This may cause high conductive pathways for CO₂ propagation that can result in an early CO₂ breakthrough.

- To determine the initial CO₂ pilot location within Murphy Creek and Bailey fields, the calculated effective permeability was mapped over these areas (Fig. 7.6). In general, Bailey Field has better reservoir connectivity (higher effective permeability) compared to Murphy Creek Field. In terms of geological analysis, the North side of Bailey Field is a good location for a CO₂ pilot.

**Figure 7.6:** Map of calculated effective permeability in Murphy Creek and Bailey fields (Red areas represent highest permeability blue for areas represent low permeability areas).
Multi-Phase Flow

In the previous section the single-phase flow equation and its application were discussed. Equation 7.9 can be changed to include multi-phase flow in the analysis of linear flow (Eq. 7.16).

\[
\frac{\Delta p(t)}{q_t} = 4.064\sqrt{24}\left(\frac{1}{(hn_fy_f)}\right)\frac{1}{\sqrt{k_{f,\text{eff}}(\lambda_o + \lambda_w + \lambda_g)}} \left(\frac{1}{(\phi c_t)_{f+m}}\right)^{1/2} \sqrt{t} + 141.2 \frac{1}{k_{f,\text{eff}}(\lambda_o + \lambda_w + \lambda_g)} S_{hf}
\]

[7.16]

Where

\[
q_t = q_o B_o + q_w B_w + q_g B_g
\]

[7.17]

\[
\lambda_o = \frac{k_{p, o}}{\mu_o}, \lambda_w = \frac{k_{p, w}}{\mu_w}, \lambda_g = \frac{k_{p, g}}{\mu_g}
\]

[7.18]

As in the single-phase flow, normalized pressure for multi-phase flow was plotted against square root of time, \(\Delta p/q_t\) versus \(t^{1/2}\). A slope with the sum of all mobile phase transmissibilities for multiphase flow can be written as in Eq. 7.19:

\[
m = 4.064\sqrt{24}\left(\frac{1}{(hn_fy_f)}\right)\frac{1}{\sqrt{k_{f,\text{eff}}(\lambda_o + \lambda_w + \lambda_g)}} \left(\frac{1}{(\phi c_t)_{f+m}}\right)^{1/2}
\]

[7.19]

\[
k_{f,\text{eff}}(\lambda_o + \lambda_w + \lambda_g) = \left(\frac{4.064}{mhn_fy_f}\right)^2 \left(\frac{24}{(\phi c_t)_{f+m}}\right)
\]

[7.20]

Where total transmissibility is:

\[
T = k_{f,\text{eff}}(\lambda_o + \lambda_w + \lambda_g)
\]

[7.21]

It should be noted that pressure is in psi, flowrate is in STB/D, time is in day, permeability is in md, and viscosity is in centipoise, thickness is in ft, formation volume factor is RB/STB, mobility of fluid is in cp\(^{-1}\), and fracture half-length is in ft.
In order to find individual transmissibilities for each phase the equation below was used (Streltsova, 1988):

$$T_f = T \left( \frac{q_f B_f}{q_i} \right)$$  \hspace{1cm} \textit{[7.22]}

Where $T_f$ is the transmissibility of mobile phase $f$ which can be written for oil phase:

$$T_o = \frac{k_{f_{\text{eff}}} k_o h}{\mu_o}$$  \hspace{1cm} \textit{[7.23]}

The sum of all phases transmissibilities, $T$, is calculated from the linear flow slope (Eq. 7.21). With a known rate, $q_f$, and formation volume factor, $B_f$, for each phase, the phase transmissibility, $T_f$ is then determined by Eq. 7.22 through well life. Knowing the phase viscosity and formation thickness, the effective permeability can be calculated for each phase (Eq. 7.23). This procedure eliminates the uncertainty of relative permeability.

For illustration of the described methodologies, two horizontal wells with 3.8 years of history were selected from Murphy Creek and Bailey areas. Those wells have similar completion, stimulation, and artificial lift practices as summarized in Table 7.3. Figure 7.7 plots the well performance data including oil flowrate, gas flowrate, pre-pump calculated bottomhole pressure, and producing-GOR for both wells. The downtime production in each well was removed so that a fair comparison can be made for the well productivity.

**Table 7.3:** Well completion and stimulation information for the Bailey and Murphy Creek wells

<table>
<thead>
<tr>
<th>Well Completion and Stimulation</th>
<th>Bailey</th>
<th>Murphy Creek</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lateral Length</td>
<td>9291 ft</td>
<td>9097</td>
</tr>
<tr>
<td>Completion Type</td>
<td>single-stage</td>
<td>single-stage</td>
</tr>
<tr>
<td>Proppant Type</td>
<td>Sand 40/70</td>
<td>Sand 40/70</td>
</tr>
<tr>
<td>Proppant Volume</td>
<td>506 Mbbl</td>
<td>552</td>
</tr>
<tr>
<td>Fracturing Fluid</td>
<td>902 Mgal</td>
<td>812</td>
</tr>
<tr>
<td>Pre-pump GOR</td>
<td>650 SCF/STB</td>
<td>450</td>
</tr>
<tr>
<td>Pump Installation</td>
<td>330 days</td>
<td>195</td>
</tr>
<tr>
<td>Post-pump GOR</td>
<td>800 SCF/STB</td>
<td>600</td>
</tr>
</tbody>
</table>
The single-phase (Eqn. 7.9) and multi-phase flow (Eq. 7.16) equations were applied to investigate the well performance differences between these two wells. Figure 7.8 shows the corresponding Cartesian plots of normalized pressure versus square root of time. The slopes from single-phase to multi-phase flow decrease slightly for both wells. This is because a flow rate for a given pressure drop includes all the phases: oil, water, and gas.

From the slopes shown in Fig. 7.8, the effective permeability for single-phase flow (Eq. 7.10) and the total transmissibility for multi-phase flow (Eq. 7.21) were calculated using the specific rock and fluid properties for each well (Table 7.4). The fluid properties were obtained from the PVT report (Chapter 4).
Table 7.4: Fluid and rock properties for the Bailey and Murphy Creek wells

<table>
<thead>
<tr>
<th>Fluid and Rock Properties</th>
<th>Bailey</th>
<th>Murphy Creek</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thickness</td>
<td>ft</td>
<td>58</td>
</tr>
<tr>
<td>Matrix Porosity</td>
<td>--</td>
<td>0.055</td>
</tr>
<tr>
<td>Fracture Porosity</td>
<td>--</td>
<td>0.005</td>
</tr>
<tr>
<td>Matrix Compressibility</td>
<td>psi⁻¹</td>
<td>1.E-06</td>
</tr>
<tr>
<td>Fracture Compressibility</td>
<td>psi⁻¹</td>
<td>1.E-05</td>
</tr>
<tr>
<td>Oil Viscosity</td>
<td>cp</td>
<td>0.476</td>
</tr>
<tr>
<td>Water Viscosity</td>
<td>cp</td>
<td>0.246</td>
</tr>
<tr>
<td>Gas Viscosity</td>
<td>cp</td>
<td>0.019</td>
</tr>
<tr>
<td>Oil FVF</td>
<td>RB/STB</td>
<td>1.500</td>
</tr>
<tr>
<td>Water FVF</td>
<td>RB/STB</td>
<td>1.048</td>
</tr>
<tr>
<td>Gas FVF</td>
<td>RB/MSCF</td>
<td>1.517</td>
</tr>
</tbody>
</table>

Table 7.5 summarizes the square root of time plot analyses results with cumulative phase production (oil, water, and gas). Although both wells have similar completions, the results suggest that the Bailey well has a greater effective permeability and total transmissibility than those of the Murphy Creek well.

Table 7.5: Summary of cumulative phase production and the results from the square root of time plot for the Bailey and Murphy Creek wells

<table>
<thead>
<tr>
<th>Production and Linear Flow Plot Results</th>
<th>Bailey</th>
<th>Murphy Creek</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cumulative Oil</td>
<td>MSTB</td>
<td>149</td>
</tr>
<tr>
<td>Cumulative Gas</td>
<td>MSCF</td>
<td>99</td>
</tr>
<tr>
<td>Cumulative Water</td>
<td>MSTB</td>
<td>29</td>
</tr>
<tr>
<td>Linear Slope (single-phase)</td>
<td>psi/RB/d¹/²</td>
<td>1.94</td>
</tr>
<tr>
<td>Effective Permeability (single-phase)</td>
<td>md</td>
<td>0.006</td>
</tr>
<tr>
<td>Oil Transmissibility (single-phase)</td>
<td>md/cp</td>
<td>0.013</td>
</tr>
<tr>
<td>Linear Slope (multi-phase)</td>
<td>psi/RB/d¹/²</td>
<td>1.62</td>
</tr>
<tr>
<td>Total Transmissibility (multi-phase)</td>
<td>md/cp</td>
<td>0.018</td>
</tr>
</tbody>
</table>

Additionally, the effective permeability to oil, $k_{f_{oil}} k_{ro}$, to water, $k_{f_{water}} k_{rw}$, and to gas, $k_{f_{gas}} k_{rg}$, were determined using the multi-phase flow equations (Eq. 7.22 and Eq. 7.23). The results are plotted in Fig. 7.9. The pump installation dates are indicated in black arrows.
Previously, the field level differences between Bailey and Murphy Creek fields were discussed including: (1) the increasing trend of solution-GOR towards Bailey Field with the increased bubble point pressure (Chapter 4) and (2) the increased effective permeability in Bailey Field (Fig. 7.6). Below is the summary combining these observations with the well-level analyses shown in Fig. 7.7 to Fig. 7.9:

- The higher the bubble point pressure, the shorter time it took for gas to separate out from the oil. The GOR in the Murphy Creek well started to increase higher than 700 SCF/STB approximately 600 days after the pump. It took 200 days for GOR to increase in the Bailey well.
- The conventional behavior of a slight drop in produced-GOR due to critical gas saturation below the bubble point pressure was not observed in the selected Bakken wells. Instead, GOR had a step-change increase due to the suppression of bubble point pressure in nano-pore sized matrix (Chapter 4) and the micro-fracture intensity.
- It is inferred that as solution GOR increases, reservoir connectivity increases due to increased micro-fracture intensity. The Bailey well has a higher effective permeability, with a higher initial producing-GOR, and more cumulative oil production than those of Murphy Creek well.

- The initial effective permeability to oil and to gas in the Bailey well is higher than those of the Murphy Creek well. The initial effective permeability to water was initially at the same level for both wells, but reduced for the Murphy Creek well after the pump installation.

### 7.2.4 Log-Log Plots of Normalized Pressure and Rate versus Material Balance Time

Material balance time is defined as the ratio of the cumulative production to the flow rate \( t_e = Q / q \) (Blasingame et al., 1991). In the absence of a pressure measurement, a log-log analysis of rate versus material balance time can also be used to complement the flow regime diagnostic. In the log-log scale of rate versus material balance time, linear flow exhibits a half slope and a transition flow regime exhibits between a half and unit slope. Okouma et al. (2012) explored the relationship between Arps flow rate exponent \( b \) and the flow regimes from log-log rate versus material balance time. Figure 7.10 shows the flow regimes (linear, transition, and pseudo boundary) and each associated slope.

![Flow regimes diagnostic using flow rate versus material balance equivalent time.](image)

**Figure 7.10:** Flow regimes diagnostic using flow rate versus material balance equivalent time.

The transient flow regime diagnostic criteria were used to constrain the Arps flow rate exponent \( b \) (Arps, 1945). Table 7.6 shows how the flow regime and the diagnostic slope’s numerical value related to Arps flow rate exponent \( b \) (Kurtoglu et al., 2013c).
Table 7.6: Comparison of slope, flow regime, and Arps flow rate exponent $b$

<table>
<thead>
<tr>
<th>Flow Regime</th>
<th>Slope on log-log Rate versus Time</th>
<th>Arp’s Flow Rate Exponent $b$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Linear</td>
<td>$\frac{1}{2}$</td>
<td>2</td>
</tr>
<tr>
<td>Transition</td>
<td>$\frac{1}{2} &lt; \text{slope} &lt; 1$</td>
<td>$1 &lt; b &lt; 2$</td>
</tr>
<tr>
<td>Pseudo Boundary</td>
<td>$&gt; 1$</td>
<td>$&lt; 1$</td>
</tr>
</tbody>
</table>

To illustrate, the Bailey and Murphy Creek wells were used to plot log-log scale of oil flow rate versus material balance time in Fig 7.11. Both wells started with a slope of 0.5 ($b=2$) indicating linear flow, both slopes increased with time. In the Bailey well, the calculated late-time slope is 0.89 ($b=1.1$) indicating a transition flow regime. The Murphy Creek well has the slope of 1.1 ($b=0.9$) indicating a pseudo boundary regime.

![Log-log plot of flow rate versus material balance time for the Bailey and Murphy Creek wells to identify flow regimes, slopes, and Arps flow rate exponent $b$.](image)

Figure 7.11: Log-log plot of flow rate versus material balance time for the Bailey and Murphy Creek wells to identify flow regimes, slopes, and Arps flow rate exponent $b$.

When flowing bottomhole pressure is not constant during the early-time production, utilizing log-log rate normalized pressure versus material balance time instead of log-log rate versus material balance time is recommended. On the log-log plot of $\frac{p_i - p_{wf}(t)}{q(t)}$ versus $t_e$, pseudo boundary flow exhibits a unit slope.

Both material balance time and actual time should be used for different purposes when utilizing log-log scale normalized pressure plots. Material balance time is used to identify flow regime, while the actual time plot is used to decipher the reasons for having different well performance behavior of wells.
To demonstrate the differences, normalized pressure data from the Bailey and Murphy Creek wells’ were plotted in a log-log scale against actual time (Fig. 7.12a) and material balance time (Fig. 7.12b). The actual time plot has real value and characteristics which reflect events. The material balance time plot masks most of the trends due to the effect of pump installation, multi-phase flow, and well interference.

![Log-log plots of normalized pressure versus time and material balance time for the Bailey and Murphy Creek wells.](image)

In summary, the Cartesian plots of normalized pressure versus time and material balance time are used to determine effective permeability (Fig. 7.8) and the log-log plots of normalized pressure versus time and material balance time are used to diagnose flow regimes (Fig. 7.12)

### 7.2.5 Log-Log Plots of Pressure and Pressure Derivative versus Material Balance Time

Modern pressure transient analysis has been greatly enhanced by the use of the derivative plot introduced by Bourdet et al. (1983). Combining pressure with pressure derivative for drawdown enables the identification of the different characteristics flow periods. Similarly, to account for the variable rate and pressure, well data should be processed using material balance time and the pressure and pressure derivative are normalized by rate. To have pressure in psi units on the vertical axis, the normalized pressure, $\frac{p_i - p_{wf}(t)}{q(t)}$, can be multiplied by a constant reference rate. This has no consequence on the interpretation, as the graph shape is not distorted on the log-log plot (KAPPA, 2012). Furthermore, the noise in daily production data diminishes by working with a normalized pressure and pressure derivative integral (Eq. 7.24 and Eq. 7.25):
\begin{align}
p(t_e) &= \frac{1}{t_e} \int_0^{t_e} (P_i - P_{eq}(t)) \frac{dt}{q(t)} \tag{7.24} \\
p'(t_e) &= \frac{\partial p(t_e)}{\partial \ln(t_e)} \tag{7.25}
\end{align}

**Figure 7.13** includes the log-log normalized pressure and pressure derivative plots for the Bailey and Murphy Creek wells. As expected, the observation was similar to the previous log-log scale material balance time plots (Fig. 7.11 and Fig. 7.12b). The Murphy Creek well is close to the pseudo boundary flow regime with a slope of 0.93. The Bailey well is still within the transition flow regime with a slope of 0.71. Another observation is that the amount of pressure differential required to produce the same rate was higher for the Murphy Creek well, indicating a poorer performance than that of the Bailey well. This observation agrees with those differences as seen in the slope of square root of time plots (Fig. 7.8).

**Figure 7.14** shows the log-log diagnostic of rate normalized pressure and pressure derivative plots for those wells. The duration of linear and transition flow regimes are highlighted in each plot. The effect of geology on flow regime behavior via simulation modeling was presented by Kurtoglu et al. (2013c).
Figure 7.14: Log-log diagnostic pressure and pressure derivative plots of North Dakota Bakken horizontal wells with 1-stage, 15-stage and 30-stage completion.

The following summarizes the observations from Fig. 7.14:

- The single-stage well stays in a linear flow (1/2 slope) during most of its production history suggesting the continuous flow from the stimulated area to the wellbore.
- The flow regime of multi-stage wells deviate to transition flow earlier. This may be the result of a complex fracture system attributed to multi-stage fracturing. Although this conclusion may not be definitive, wells do stay in transition flow for a long period of time without experiencing boundary-dominated flow behavior.
CHAPTER 8

NUMERICAL MODELING

To integrate the geological description of the Bakken Formation with core measurements and well testing results, a multi-layer compositional reservoir simulation model (ECLIPSE™ E300) was built to history match production data from a hydraulically fractured horizontal well drilled in Middle Bakken Formation. This chapter presents the reservoir modeling philosophy to evaluate a Bakken well performance under primary depletion, waterflooding, and CO2 injection.

The following sections include (1) model construction, (2) integrated approach in history-matching and forecasting primary production, (3) results of both single- and dual-porosity models, (4) sensitivity of the key parameters on Bakken production, (5) evaluation of waterflood performance, (6) prediction of CO2 injection, and (7) well spacing.

8.1 Model Construction

This section introduces the construction of the compositional simulation model regarding the formulation, gridding, input data, and model types.

8.1.1 Formulation

The reservoir simulation model was built with the following input and assumptions:

- Five components (N2-C1, CO2, C2-C3, C4-C6, C7-C80) EOS parameters were tuned against pressure depletion and CO2 laboratory swelling test data to generate EOS parameters required by E300 (Chapter 4).
- Three-phase relative permeability curves were used for both matrix and fracture media (Chapter 5).
- Rock compaction tables were generated based on laboratory measured data for both matrix and fractures (Chapter 4).
- Capillary pressure was neglected in the base model due to the lack of laboratory data, but its effect on recovery was investigated using a predicted capillary pressure curve.
- The fracture intensity was modeled using a matrix shape factor for the dual-porosity model. Initial prediction was made using the core-based fracture intensity (Chapter 5).
- Neither the injection of frac fluid during hydraulic fracture stimulation nor frac fluid recovery was modeled. The history-match was done for a primary depletion.
- Logarithmic gridding was used to capture transient flow. The model has 399 cells in the x-direction, 347 in the y-direction, and 4 vertical layers to represent the Upper Bakken Shale, Middle Bakken, Lower Bakken Shale, and Three Forks formations.
The base model consists of a horizontal well with a 15-stage completion in a 1280-acre reservoir. Three wells were used to study multi-well production and EOR schemes.

- Hydraulic fracture height was constrained within Middle Bakken.
- Initial reservoir pressure for each layer was obtained from mini-frac tests of a vertical well.
- Diffusion effect within the oil and gas phases were not included due to numerical convergence issues.

The reservoir performance was modeled using both single- and dual-porosity models (Section 8.4). The dual porosity model captures the flow behavior that comprises both low matrix permeability and high fracture network permeability. During pressure depletion, flow is driven from matrix to fractures, and then to a wellbore. To capture this flow potential, a pseudo-steady state (PSS) dual-porosity model was used to simulate Bakken well production.

Because matrix permeability is extremely low in Bakken, the pressure change inside a matrix stays at transient state for a long period of time. Torcuk et al. (2013) showed that an un-steady state (USS) dual-porosity model yields the same pressure drop as that of analytical and numerical PSS dual-porosity model at the late time period. Therefore, this study used PSS dual-porosity model to forecast a long-term well production.

To explain the difference in fluid flow for single- and dual-porosity media, the pressure diffusivity equation for the single phase, slightly compressible flow in dual-porosity media can be written as:

\[
\nabla \left[ \left( 0.006328 \frac{k_{f,\text{eff}}}{\mu} \right) \Delta p_f \right] + \tau = \left( \varphi \chi \right)_f \frac{\partial \Delta p_f}{\partial t}
\]

Where

\[
\Delta p_f = p_i - p_{wf}
\]

\[
k_{f,\text{eff}} = k_f \varphi_f
\]

and \(\tau\) is a source term representing the fluid transfer rate per unit rock volume between natural fractures and matrix. For pseudo steady-state model, Warren and Root (1963) proposed:

\[
\tau_{\text{PSS}} = \left( 0.006328 \right) \sigma \frac{k_m}{\mu} \left( \Delta p_f - \Delta p_m \right)
\]
In Eq. 8.4, $\sigma$ is the matrix shape factor for the cubic matrix blocks surrounded by fractures on all sides, and was given by Kazemi (1987):

$$\sigma = 4 \left( \frac{1}{L_x^2} + \frac{1}{L_y^2} + \frac{1}{L_z^2} \right)$$  \[8.5\]

Where $L_x$ is fracture spacing, and assumed to be equal to $L_y$ and $L_z$ in the base model. The shape factor accounts for the matrix-fracture interface area per unit volume in dual-porosity media. It defines the size of the matrix grid blocks to represent the fracture intensity.

In the single-porosity model, Eq. 8.1 can be simplified to Eq. 8.6 by neglecting the source term, $\tau$:

$$\nabla \left[ 0.006328 \frac{k_{eff}}{\mu} \Delta p_f \right] = (\rho c_v)_f \frac{\partial \Delta p_f}{\partial t}$$  \[8.6\]

Where the effective fracture permeability, $k_{f,eff}$ in Eq. 8.1 was replaced by effective media permeability, $k_{eff}$ (Eq. 8.6) in the single porosity model which is the combination of matrix and natural fractures (Eq. 8.7).

$$k_{eff} = k_m + k_f \phi_f$$  \[8.7\]

### 8.1.2 Modeling Philosophy

Both pressure transient (Chapter 6) and rate transient analyses (Chapter 7) exhibit a long linear flow. This can be explained by (1) the sustainable flow from a stimulated area to a wellbore through fractures and (2) the far-field matrix contribution to long-term production. Isolated-SRV around a hydraulic fracture can be attributed to poor completion, high drawdown during initial production, low matrix permeability, and low fracture intensity; all of which may cause a deviation from linear flow.

To illustrate this concept, two Eagle Ford wells with different rock and fluid properties were included with a typical Bakken well. Figure 8.1 shows the linear flow analyses and conceptual fracture patterns (SRV schematics) for an Eagle Ford gas well, an Eagle Ford volatile oil well in South Texas, and a Bakken oil well in North Dakota. The major difference among these three wells is the duration of the linear flow, which is used to contrast SRV geometry for each well. More details about the modeling of volatile oil case with the isolated-SRV area were presented in a study by Kurtoglu et al. study (2013b).
The initial estimate of the SRV dimension can be obtained from the linear flow analysis (Wattenbarger et al., 1998; Rasdi and Chu, 2012). The uncertainty of SRV size can be minimized by integrating diagnostic well flow regime plots. In this study, both well production and well flow regimes from pressure and rate transient tests were history-matched.

**Figure 8.1:** Square root of time plots for Eagle Ford in South Texas and Bakken in North Dakota demonstrating different SRV geometries due to different rock and fluid types.

The simulation model had two reservoir regions: the stimulated reservoir volume (SRV) and the un-stimulated reservoir volume (URV). The URV is defined as the far-reservoir region that has the matrix permeability with less intense fracture density, whereas SRV is the near-wellbore region with enhanced permeability, due to natural fractures and hydraulic fractures. **Figure 8.2** illustrates these regions and shows the dimensions of the simulation model.
8.1.3 Grid Construction

As mentioned earlier, fluid transfer in a PSS dual porosity model is questionable in the early time. Although the PSS model is unable to capture the very long transient behavior in the extremely low-permeability matrix blocks, very fine gridding especially in the vicinity of wellbore leads to better capture of early time phenomena, such as well-block storage and propagation of pressure perturbation (Darishchev et al., 2013).

Therefore, a very fine gridding was used between hydraulic fractures and between the wellbore and the tip of the fractures (Fig. 8.3). This fine gridding was not only important during depletion (flow from matrix to micro and macro fractures, to hydraulic fractures) but also during injection where the flow hierarchy is reversed (flow from fractures, to matrix). The entire reservoir was discretized strategically with a logarithmic gridding algorithm in three sub-domains to include hydraulic fractures, SRV and URV regions.

![Reservoir discretization with logarithmic gridding.](image)

Hydraulic fractures were modeled based on the completion strategy of the selected well. For a multi-stage completion, the reservoir fluid entry to the wellbore was simulated through hydraulic fractures. The initial estimate of hydraulic fracture permeability was calculated assuming infinite fracture conductivity using Eq. 8.8.

\[
F_{cD} = \frac{k_{hf} w_{hf}}{x_f k_m}
\]  

[8.8]

Hydraulic fracture permeability \( k_{hf} \) was then used to history-match early well production profile. In Eq. 8.8, matrix permeability \( k_m \) was obtained from core measurement, fracture half-length \( x_f \) was
estimated from the fractured vertical well pressure buildup, and fracture width \( w_{hf} \) was assigned a value based on hydraulic fracture conductivity. The width of the hydraulic fractures for the grid blocks was 0.5 ft.

### 8.1.4 Model Input Data

To compare the results between the primary depletion and the EOR production scenarios, all the simulation models were run using the five-component tuned EOS (Fig. 4.15 and Fig. 4.16). Laboratory measured pressure-dependent permeabilities for matrix and fracture were included in the reservoir simulation model to capture the loss of permeability during depletion as described in Chapter 5. Additional core data used in the model include the matrix permeability, the relative permeability curves, and the core based fracture intensity.

The matrix shape factor (Eq. 8.5) was used to calculate fracture intensity and spacing values using the core based fracture data. Table 8.1 summarizes those average fracture intensity and spacing values for each formation. The Lodgepole formation has the highest fracture intensity. This layer was deactivated in the model due to computational issues.

**Table 8.1:** Core-based fracture intensity and spacing for each formation, and the values used in the history-match model

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Lodgepole</th>
<th>Upper Bakken</th>
<th>Middle Bakken</th>
<th>Lower Bakken</th>
<th>Three Forks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Core Based</td>
<td>Fracture Intensity #/ft</td>
<td>2.67</td>
<td>0.24</td>
<td>0.54</td>
<td>0.98</td>
</tr>
<tr>
<td></td>
<td>Fracture Spacing ft</td>
<td>0.37</td>
<td>4.16</td>
<td>1.86</td>
<td>1.02</td>
</tr>
<tr>
<td>History-Match Model</td>
<td>Sigma ft²</td>
<td>--</td>
<td>1.28</td>
<td>2.32</td>
<td>1.54</td>
</tr>
<tr>
<td></td>
<td>Fracture Spacing ft</td>
<td>--</td>
<td>3.07</td>
<td>2.27</td>
<td>2.79</td>
</tr>
</tbody>
</table>

### 8.1.5 Model Types

A multi-layer homogenous model with constant fracture and matrix properties was built to history-match primary depletion. To illustrate the impact of reservoir heterogeneity on waterflooding, and CO₂ injection, a geologically characterized model was built.

**Homogenous Model**

In the homogenous model the matrix and fracture properties are uniform in each layer. The matrix permeability was referenced from the core data, the fracture permeability was derived from the well test analyses, and the shape factor in SRV was calibrated by pressure buildup test was. The calibration of the model against field pressure buildup test will be explained in the following section (Section 8.2.2). Figure 8.4 represents the matrix and fracture permeability, and the shape factor for the dual-porosity
homogenous reservoir model. Figure 8.4 (b) displays the enhanced permeability area (SRV) with the well locations. Uniform matrix permeability represents average core permeability and fracture permeability displays the change in SRV and URV. Higher fracture intensity (higher shape factor) was included in the near-wellbore due to hydraulic fracturing (Fig. 8.4c).

**Heterogeneous Model**

To represent the realistic reservoir characteristics, a heterogeneous matrix and fracture petrophysical model was built using a combination of core analyses and well log data.
For a given layer, the mean values of matrix and fracture permeability and porosity in this heterogeneous model were the same as those used in the homogenous model. Figure 8.5 represents the variation of matrix and fracture permeability, and the shape factor in the heterogeneous model. The fracture permeability and shape factor in SRV were multiplied by the same multiplier to increase the reservoir connectivity as it was done in the homogenous model.

8.2 Primary Recovery

The simulation model was used to history-match primary depletion, characterize rate decline behavior, and determine well flow regimes. This numerical approach integrates pressure and rate based diagnostic plots with decline curve methods to predict future performance.

The base model was built to match a Middle Bakken horizontal well with 1.2-years of production history in Reunion Bay. The model was then used to test single- and dual-porosity approaches, and extended to three well-models to evaluate CO₂ injection scenarios. The reason to select a well in Reunion Bay was the abundance of available data in this field such as well tests, special PVT lab test, and core analyses. The sensitivity analyses were applied to capture the major differences among Murphy Creek, Bailey, and Reunion Bay fields.

8.2.1 History-Match Well Production

Before attempting to match well history, the linear flow analysis was applied to the well data to get an initial effective permeability. The data required for this analysis reflects the reservoir model input such as PVT, fracture numbers, fracture half-length, matrix and fracture porosity, and the compressibilities. Using the linear flow slope, shown in Fig. 8.6, the fracture permeability of 4.6 md was calculated. The effective fracture permeability of 0.026 md was then obtained by multiplying a fracture porosity of 0.056 (fraction) in the SRV with a fracture permeability of 4.6 md. Figure 8.6 presents the linear flow plot and the corresponding data for the calculation.

No deviation from the linear flow was observed in Fig. 8.6. This indicates a fracture pattern in a box type SRV around the wellbore as shown in Fig. 8.1. Table 8.2 summarizes the dimensions of the reservoir, SRV, and hydraulic fracture. Reservoir boundary represents the drilling spacing unit of 1280 acres. The total thickness is 287 ft of which 49.5 ft is Middle Bakken. The hydraulic fracture height growth was limited to Middle Bakken. The final history-match model has a single well surrounded by SRV region with a width of 724 ft and a length of 8800 ft.
Table 8.2: Formation properties and hydraulic fracture properties for a horizontal well in the dual-porosity model

<table>
<thead>
<tr>
<th>Model Dimension</th>
<th>Reservoir</th>
<th>SRV</th>
<th>Hydraulic Fracture</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area</td>
<td>1277</td>
<td>146</td>
<td>Number of Stages</td>
</tr>
<tr>
<td>Well Length</td>
<td>8800 ft</td>
<td>724</td>
<td>15</td>
</tr>
<tr>
<td>Reservoir Width</td>
<td>5280 ft</td>
<td></td>
<td>Half-Length</td>
</tr>
<tr>
<td>Reservoir Length</td>
<td>10537 ft</td>
<td></td>
<td>Width</td>
</tr>
<tr>
<td>Formation</td>
<td></td>
<td></td>
<td>0.5 ft</td>
</tr>
<tr>
<td>Thickness</td>
<td>287 ft</td>
<td></td>
<td>Height</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>49.5 ft</td>
</tr>
</tbody>
</table>

The simulation model was run with oil rate control to history match the pressure and gas production profile. Figure 8.7 displays reasonable model prediction against the history data (oil rate, gas rate, BHP, and cumulative oil production). The difference in gas rate was attributed to the difference in PVT model data compared to the well initial producing-GOR.
Figure 8.7: History match results for a 15-stage horizontal well, dual-porosity model.

Both homogenous and heterogeneous models have the same mean values of permeability and porosity for each layer. Table 8.3 summarizes those formation properties for the history-match model including thickness, matrix and fracture permeability, and porosity in URV and SRV. The history-match model has an effective Middle Bakken permeability of 0.031 md in SRV. This permeability is consistent with mini-DST and mini-frac test results as described in Chapter 5.
Table 8.3: Matrix and fracture properties of each formation in the dual-porosity model

<table>
<thead>
<tr>
<th>Regions</th>
<th>URV</th>
<th>SRV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameters</td>
<td>Upper Bakken</td>
<td>Middle Bakken</td>
</tr>
<tr>
<td><strong>Thickness</strong></td>
<td>ft</td>
<td>19.80</td>
</tr>
<tr>
<td><strong>Matrix Permeability</strong></td>
<td>md</td>
<td>8.99E-06</td>
</tr>
<tr>
<td><strong>Matrix Porosity</strong></td>
<td>fraction</td>
<td>0.055</td>
</tr>
<tr>
<td><strong>Fracture Intrinsic Permeability</strong></td>
<td>md</td>
<td>1.15E-02</td>
</tr>
<tr>
<td><strong>Fracture Porosity</strong></td>
<td>fraction</td>
<td>0.0020</td>
</tr>
<tr>
<td><strong>Effective Fracture Permeability</strong></td>
<td>md</td>
<td>2.29E-05</td>
</tr>
<tr>
<td><strong>Sigma</strong></td>
<td>ft^2</td>
<td>1.28</td>
</tr>
<tr>
<td><strong>Fracture Spacing</strong></td>
<td>ft</td>
<td>3.07</td>
</tr>
</tbody>
</table>

The reservoir pressures were obtained from the mini-frac tests conducted in each layer. Table 8.4 includes reservoir pore volume, original oil in place, reservoir pressure at both initial and final conditions (37-year) for each layer and SRV.

Table 8.4: Initial reservoir pressure, pore volume, and hydrocarbon volume in the simulation model

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Initial Reservoir Condition</strong></td>
<td>Totals</td>
</tr>
<tr>
<td><strong>Pore Volume</strong></td>
<td>MMRB</td>
</tr>
<tr>
<td><strong>OOIP</strong></td>
<td>MMRB</td>
</tr>
<tr>
<td><strong>Initial Pressure</strong></td>
<td>psi</td>
</tr>
<tr>
<td><strong>Initial Surface Condition</strong></td>
<td>Oil</td>
</tr>
<tr>
<td><strong>Gas</strong></td>
<td>MMMSCF</td>
</tr>
</tbody>
</table>

- The OOIP is 56.6 MMSTB. Middle Bakken has 8.4 MMSTB.
- The EUR of oil is 596 MSTB from all layers.
- The EUR of gas is 503 MSCF from all layers.
- The oil recovery factor for all formations is 1.05%. This recovery factor represents the cumulative oil production divided by OOIP of all formations.
- The oil recovery to **Middle Bakken** is 7.10%. This recovery factor represents the cumulative oil production divided by OOIP of Middle Bakken.

- The pressure depletion from 7802 psi to 1972 psi is observed in SRV after 37-years of production. The pore pressure in the URV and other layers stay above 7000 psi (with a less than 1000 psi depletion). Because the average reservoir pressure decreases very slowly out of SRV, an undersaturated reservoir condition may delay GOR increase as discussed in **Chapter 7**.

**8.2.2 Model Calibration**

Although the model had a reasonable match with the well history, the uncertainty of the reservoir input data may result in a non-unique history-match. Therefore, several diagnostic plots of rate and pressure response were applied to confirm the history-match. The following list summarizes the approaches and their related plots used in model calibration:

(1) Pressure buildup data using log-log pressure and pressure derivative plot versus shut-in time.

(2) Drawdown analysis using log-log pressure and pressure derivative plot versus material balance time.

(3) Linear flow analysis using square root of time plot.

**1. Pressure Buildup Analysis**

An offset Middle Bakken horizontal well had a pressure buildup test. The shut-in time was 10 days. The objective was to use this test result to capture the correct well flow regime in the simulation model while maintaining the history-match. **Figure 8.8** displays the model pressure build up and diagnostic plot with the field data. The list below summarizes the workflow:

- Synthetic pressure buildup was created at the end of the stable production (**Fig. 8.8a**)
- Log-log pressure and pressure derivative plot was used for flow regime identification (**Fig. 8.8b**)
- The log-log pressure and pressure derivative plot from the model was superimposed with the field (**Fig. 8.8b**).

- The fracture permeability and shape factor in SRV were changed until a reasonable history-match was obtained in log-log plot pressure and pressure derivative plot.

This workflow required several iterations. For instance, although a perfect rate and pressure history match model was obtained, the synthetic pressure buildup response exhibited a typical dual porosity shape in pressure derivative. This was attributed to the non-representative fracture and matrix properties. The best match with the field pressure buildup test was obtained when a micro-fracture spacing of 0.77 ft in the SRV was used (**Table 8.3**). The flow regime from both the model and field indicated a half slope in the log-log plot.
2. Rate Transient Analysis

The well flow rate and pressure during drawdown was further analyzed using log-log pressure and pressure derivative versus material balance time plot as described in Chapter 7. Figure 8.9 represents this plot including both the model and field response. Through the well history both exhibited a half slope, and then followed by a transition flow. The continuity of transition flow regime without deviating to unit flow is attributed to micro-fractures and the long-transient response is affected by low-permeability matrix.

Figure 8.9: Log-log plots of pressure and pressure derivative versus material balance time for the history-match well.
3. Linear Flow Analysis

The main flow regime is characterized by linear flow both in pressure build up and well drawdown responses. Therefore, the linear flow analysis using square root of time plot was applied to the model data to calculate effective fracture permeability (Fig. 8.10). This permeability value of 0.024 md was then compared against the simulation input data of 0.031 md (Table 8.3) and the permeability of 0.026 md calculated using the field data with the same approach (Fig. 8.6). These results show the consistency between the different evaluation methods.

![Figure 8.10: Analysis of history-matched production data from reservoir simulation.](image)

<table>
<thead>
<tr>
<th>Model - Production Data Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \mu )</td>
</tr>
<tr>
<td>( B )</td>
</tr>
<tr>
<td>( h )</td>
</tr>
<tr>
<td>( n_f )</td>
</tr>
<tr>
<td>( y_f )</td>
</tr>
<tr>
<td>( \varphi_m )</td>
</tr>
<tr>
<td>( \varphi_f )</td>
</tr>
<tr>
<td>( c_{cm} )</td>
</tr>
<tr>
<td>( c_{cf} )</td>
</tr>
<tr>
<td>( m )</td>
</tr>
<tr>
<td>( b )</td>
</tr>
<tr>
<td>( k_{f, eff} )</td>
</tr>
<tr>
<td>( k_f )</td>
</tr>
<tr>
<td>( S_h )</td>
</tr>
</tbody>
</table>

8.2.3 Forecasting Well Production

The decline behavior of the well flow rate was analyzed using Arps hyperbolic equation. As explained in Chapter 7, this method has its limitations and assumptions for the use in Bakken wells. The initial estimate of constant \( b \) factor was driven by analyzing two horizontal wells with openhole single-stage completions and a horizontal well with 15-stage completion; all three wells have more than three years of production. Their decline exponent \( b \) was calculated through time using Eq. 7.8. Figure 8.11a represents the \( b \) exponent profile for these wells. This suggests a \( b \) exponent between 1.4 and 1.6. In addition, log-log monthly oil rate versus material balance time plot was used to see the trend of the field and model data while determining the slope for the estimation of \( b \) exponent. Figure 8.11b displays this plot indicating \( b \) exponent of 1.5 on both model and field data.

The decline exponent \( b \), of 1.50 was then used to forecast 37 years of production with a terminal decline of, \( D_{min} \), of 6%. This method forecasted ultimate recovery of 592,000 bbls.
Figure 8.11: (a) Arps decline $b$ exponent for three Bakken wells, (b) Monthly average oil rate versus material balance time plot for the field and model data.

In addition, the forecasted flow rate from the simulation model was back-matched by the decline curve analysis. This decline exponent was 1.55 using a terminal decline of 6%. This method estimated ultimate recovery of 597,000 bbls. The forecast from the simulation model was 596,000 bbls. Figure 8.12 shows monthly oil production and cumulative oil production from those methods comparing against the field data.

Figure 8.12: (a) Oil rate history match and forecast data, (b) Cumulative oil production profile from field, model, and decline curve analysis.
8.3 Comparison between Single- and Dual-Porosity Models

The history-match dual porosity model was converted to a single porosity model to evaluate the performance differences. The model conversion consists of (1) calculating the effective permeability in SRV and URV regions using Eq. 8.7, (2) removing relative permeability curve for fracture, (3) adjusting total porosity to maintain the initial material balance, and (4) keeping the hydraulic fracture conductivity the same. The summary of the input data for the history-match single porosity model is listed in Table 8.5. The effective system permeability of 0.0307 md and total matrix porosity of 0.057 (fraction) in Middle Bakken SRV are similar to those in the dual-porosity model.

<table>
<thead>
<tr>
<th>Regions</th>
<th>Parameters</th>
<th>URV</th>
<th>SRV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Upper Bakken</td>
<td>Middle Bakken</td>
<td>Lower Bakken</td>
</tr>
<tr>
<td>Thickness</td>
<td>ft</td>
<td>19.80</td>
<td>49.50</td>
</tr>
<tr>
<td>Matrix Permeability</td>
<td>md</td>
<td>1.89E-04</td>
<td>1.18E-03</td>
</tr>
<tr>
<td>Matrix Porosity</td>
<td>fraction</td>
<td>0.055</td>
<td>0.057</td>
</tr>
</tbody>
</table>

Table 8.5: Matrix properties of each formation in the single-porosity model

If the permeability of the system is believed to be matrix only, each layer should be characterized with matrix core permeability. Therefore, the single-porosity model was run with a measured matrix core permeability to show the differences in oil recovery among the various approaches.

Figure 8.13 (a) displays the oil rate forecast from (1) the history-match dual porosity model with matrix and fracture media, (2) the history-match single porosity model with an effective permeability, and (3) a single porosity model with a matrix core permeability. This indicates that a single-porosity system, based on matrix core permeability alone, is not sufficient to validate well performance without additional contributions from micro and macro fractures. Figure 8.13 (b) compares the cumulative production profiles between single- and dual-porosity models against the well history.

Both single- and dual-porosity models showed a reasonable match with the history and followed the similar decline flow rate up to 4-years of production. Later, a higher decline rate was observed in the single-porosity model than that in dual-porosity case. Therefore, in the long term a better recovery was obtained from the dual-porosity model. This is attributed to the micro-fractures involved in the dual-porosity model. Table 8.6 summarizes the estimate ultimate recovery for three models shown in Fig. 8.13 (a). The results suggest that the estimated oil recovery from the dual-porosity model is 7.10%, for the single porosity effective permeability model is 5.42%, and for the single porosity matrix permeability model is 0.29%.
Figure 8.13: (a) Oil rate forecast from single and dual porosity models against field, (b) Cumulative production forecast from single and dual porosity models against field.

Table 8.6: Comparison of oil recovery between single- and dual-porosity models

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Dual-Porosity</td>
<td>Primary</td>
<td>Matrix and Fracture</td>
<td>596</td>
<td>7.10</td>
</tr>
<tr>
<td>Single-Porosity</td>
<td>Primary</td>
<td>Effective</td>
<td>455</td>
<td>5.42</td>
</tr>
<tr>
<td>Single-Porosity</td>
<td>Primary</td>
<td>Matrix</td>
<td>24</td>
<td>0.29</td>
</tr>
</tbody>
</table>

To explain the differences in flow hierarchy during primary depletion between single and dual porosity models, the pressure distribution through time around a single hydraulic fracture was displayed in Fig. 8.14.

Figure 8.14: Comparison of the pressure distribution for single and dual porosity model.

The affected volumetric depletion is broader in the single-porosity model as compared with that of dual-porosity model. This is because direct pore volume connectivity between matrix and hydraulic fractures in a single porosity model. However, in dual porosity model, flow is from matrix flow to the
imbedded fractures, and to the hydraulic fractures. Therefore, a single-porosity model can provide similar depletion drive forecasts as a dual porosity model; the latter is more reliable for CO2 applications because of the inherent flow hierarchy controls.

8.4 Sensitivity Analyses

The simulation model presented above was used for the sensitivity analysis. The motivation behind this work was to investigate the impact of the key drivers on well production (Chapter 7) and areal differences in fluid properties (Chapter 4) among Reunion Bay, Bailey, and Murphy Creek fields. The base model includes 15-stage frac completion, drilled through 49.5 ft Middle Bakken Formation, and has an initial 792 SCF/STB solution-GOR.

8.4.1 Formation Thickness

The primary production is mostly controlled by SRV within Middle Bakken formation (Table 8.4). This motivates to apply sensitivity analysis around Middle Bakken thickness to change the stimulated reservoir volume. The thickness of 49.5 ft in the base model was changed by 30% to obtain 34.6 and 64.3 ft. The hydraulic fracture height was constrained within the Middle Bakken thickness as in the base model. Thus, increase in thickness results in an increase in the stimulated area.

Figure 8.15 represents the cumulative oil and cumulative gas production for the simulation models with 34.6, 49.5, and 64.3 ft of Middle Bakken thickness. The oil recovery increases by 1.51% from 34.6 to 49.5 ft, and from 49.5 to 64.3 ft. Increase in Middle Bakken thickness from North to East direction of the study area (from Murphy Creek to Bailey, and to Reunion Bay) may be the one of the reasons for wells in Reunion Bay to have a higher productivity in general.

![Figure 8.15: Sensitivity of formation thickness on oil and gas production.](image-url)
8.4.2 Well Completion

As discussed in Chapter 7, completion technology has advanced during the development of Bakken. The model was used to demonstrate the impact of increased stage numbers in well completion while keeping the SRV dimension identical both vertically and horizontally.

Figure 8.16 shows the cumulative oil and cumulative gas production for the simulation models with 8, 15, and 30-stage wells. The more stages the more hydrocarbon production was observed due to the increased surface area. The increase in oil recovery is 1.17% more from 8 to 15-stage, whereas it is only 0.19% from 15-stage to 30-stage. This study provides insights about the optimum stage number and shows that 30-stage frac completion accelerates production early in the well life with a slightly higher EUR in the long-term.

![Figure 8.16: Sensitivity of stage number on oil and gas production.](image)

8.4.3 Fluid Properties

The fluid properties in Reunion Bay, Bailey, and Murphy Creek were summarized in Table 5.1. The base model in Reunion Bay used the fluid Sample #2. The fluid characterization was carried out for Sample #6 for Bailey and Sample #8 for Murphy Creek. The simulation models were run by changing only PVT tables corresponding to specific field.

Figure 8.17 shows the cumulative oil and cumulative gas production for the simulation models including Reunion Bay, Bailey, and Murphy Creek PVT tables. The tuned GOR is 380 SCF/STB in Murphy Creek, 641 SCF/STB in Bailey, and 792 SCF/STB in Reunion Bay. The cumulative gas production profiles follow this trend; the highest gas production was observed in Reunion Bay. However, oil viscosity with respect to pressure has a similar trend between Murphy Creek and Bailey (Fig. 5.7). Oil viscosity is the lowest in Reunion Bay. Therefore, the cumulative oil production is higher in Reunion Bay well and similar between Murphy Creek and Bailey wells.
Figure 8.17: Sensitivity of PVT properties on oil and gas production.

Table 8.7 summarizes the results of the sensitivity analyses. EUR for oil and gas are compared against the base model. Within the given range of uncertainty, thickness in turn stimulated volume has the highest impact on recovery, followed by number stage of completion and GOR value.

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Base</td>
<td>15</td>
<td>49.5</td>
<td>792</td>
<td>615</td>
<td>7.32</td>
<td>523</td>
<td>8.4</td>
</tr>
<tr>
<td>Thickness-1</td>
<td>15</td>
<td>34.7</td>
<td>792</td>
<td>487</td>
<td>5.81</td>
<td>387</td>
<td>6.2</td>
</tr>
<tr>
<td>Thickness-2</td>
<td>15</td>
<td>64.4</td>
<td>792</td>
<td>742</td>
<td>8.83</td>
<td>661</td>
<td>10.6</td>
</tr>
<tr>
<td>Multi-stage-1</td>
<td>8</td>
<td>49.5</td>
<td>792</td>
<td>517</td>
<td>6.15</td>
<td>339</td>
<td>5.5</td>
</tr>
<tr>
<td>Multi-stage-2</td>
<td>30</td>
<td>49.5</td>
<td>792</td>
<td>631</td>
<td>7.51</td>
<td>619</td>
<td>10.0</td>
</tr>
<tr>
<td>PVT-1</td>
<td>15</td>
<td>49.5</td>
<td>380</td>
<td>542</td>
<td>6.45</td>
<td>189</td>
<td>3.0</td>
</tr>
<tr>
<td>PVT-2</td>
<td>15</td>
<td>49.5</td>
<td>641</td>
<td>553</td>
<td>6.58</td>
<td>350</td>
<td>5.6</td>
</tr>
</tbody>
</table>

8.5 Waterflooding

The results from history-match simulation model and well tests show the importance of effective permeability representing the contributions from permeable flow paths in the reservoir. This understanding encourages exploring waterflooding performance using the dual porosity reservoir simulation model that had been primary history-matched. The history-match primary depletion model presented above was extended to include two additional horizontal wells with 15-stage completion. For
the waterflooding case, the center well was converted to a horizontal water injector and well spacing is 660 ft.

In the depletion scenario, three wells start production at the same time at a maximum oil rate of 700 BBL/D and a minimum pressure of 800 psi for 40-year of production. In the waterflood model, three wells produced for 450 days and then the center well was converted to a water injector. The injector well was controlled by a maximum injection pressure of 8100 psi and 1000 bbl/d of water rate. The injection pressure limit was designed based on the fracture gradient information obtained from the mini-frac test.

The following section discusses the effect of reservoir heterogeneity and water-oil capillary pressure on waterflood performance.

8.5.1 Effect of Reservoir Heterogeneity

Both homogenous (Fig. 8.4) and heterogeneous models (Fig. 8.5) were used to evaluate waterflood potential. Figure 8.18 shows the pressure profile at 40 year, water saturation after 2-years of injection, and water saturation at 40 year for the homogenous model.

![Figure 8.18: Waterflood: Middle Bakken pressure and water saturation profiles in the homogenous model.](image)

The followings summarize the observations:
- With the increasing reservoir pressure around the injector and propagating to the producers, the direction of flow starts from the micro fractures to the hydraulic fractures and, then to the wellbore of the producers. This flow path eventually enhances the oil production for the side wells (Fig. 8.18a).
- After 2-years of injection, water still did not reach either of the producers (Fig. 8.18b).
- After 40-years of injection, high water saturation of 75 to 100% between the injector and producers was observed. This mechanism helps to displace the oil in the fractures, is unable to reach the matrix (Fig. 8.18c).

Figure 8.19 shows oil production from well P1 or P2 of Fig. 8.18. The water injection rate of 1000 bbl/d decreases to 176 bbl/d after 10 days of injection, and stabilizes to 70 bbl/d after 150 days of injection until the end of the injection period. The incremental oil was observed at around 600 days. The higher oil flow rate in the waterflood model lasted for 20 years until water breakthrough occurs. The incremental oil recovery is 0.79% at year 20. Later, the flow rate stays below than the depletion scenario. Thus, the incremental oil recovery is decreased to 0.66% at year 40.

![Figure 8.19: Primary depletion and water injection models: Comparison of a side well oil rate and cumulative oil production in the homogeneous model.](image)

The heterogeneous model adapts the same production and injection strategy as that of the homogenous model. Figure 8.20 shows the pressure and water saturation distributions.
- Due to the effect of heterogeneity, the pressure propagation varies in the vicinity of the wellbore. This defines injection flow paths to the producer wells (Fig. 8.20a).
- The water saturation has a greater propagation at the heel of the well due to increased connectivity (Fig. 8.20b).
- Even after 40-years of injection, the areas with lower fracture permeability and fracture spacing have limited sweep efficiency. Most of the stages in the injection well have a water saturation of 100% and up to 75% for the producer wells (Fig. 8.20c).
(a) Reservoir Pressure at 40 year
(b) Water Saturation after 2-year of injection
(c) Water Saturation at 40 year

**Figure 8.20:** Waterflood: Middle Bakken pressure and water saturation profiles in the heterogeneous model.

**Figure 8.21** represents the side well (P1 or P2 in **Fig. 8.20**) oil production between primary depletion and waterflood. The incremental oil was observed at around 550 days which is earlier than the homogenous case. The higher oil flow rate in the waterflood model lasted to the end of well life. The incremental oil recovery is 0.92% at year 20 and increased up to 1.12% at year 40.

**Figure 8.21:** Primary depletion and water injection models: Comparison of a side well oil rate and cumulative oil production in the heterogeneous model.

**Table 8.8** summarizes the results of homogenous versus heterogeneous model for the side oil production well. Heterogeneous waterflood model provided a better sweep efficiency than that of
homogeneous case. This is attributed to the various fracture intensity in the heterogeneous model whereas homogenous model has an uniform fracture intensity.

Table 8.8: Summary of primary depletion and waterflood model results for homogenous and heterogeneous models

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
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</tr>
</thead>
<tbody>
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<td>Homogenous Model</td>
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<td>5.71</td>
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<tr>
<td></td>
<td>Waterflood</td>
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<td>5.00</td>
<td>535</td>
<td>6.37</td>
</tr>
<tr>
<td>Heterogeneous Model</td>
<td>Primary</td>
<td>326</td>
<td>3.88</td>
<td>440</td>
<td>5.24</td>
</tr>
<tr>
<td></td>
<td>Waterflood</td>
<td>403</td>
<td>4.80</td>
<td>534</td>
<td>6.36</td>
</tr>
</tbody>
</table>

Although the waterflood in heterogeneous model provides an incremental recovery of 0.92% at year 20, there are key elements to consider for a field application including injection pressure, injection fluid type, and fluid flow path during injection.

- In terms of injection pressure, achieving a pressure of 8100 psi is economically challenging considering the additional head due to 10,500 ft vertical depth and water density. To maintain such a high injection pressure requires more powerful compression facilities than used in primary depletion.

- The incremental production in waterflooding is attributed to the micro fractures which are also concluded as a key driver for primary production. The oil is mobilized from micro-fractures to the producers. Thus, a high reservoir connectivity area such as Reunion Bay can be a good choice for waterflood injection.

- The simulation model was not used to test the effect of water salinity as an injection fluid. However, the low salinity brine imbibition test results (Chapter 5) suggests the use of low salinity water for a waterflood injection.

8.5.2 Effect of Capillary Pressure

Capillary pressure effect on waterflood performance was not included in the previous models due to the lack of laboratory data. However, its effect on recovery was investigated using a predicted capillary pressure curve. The following water-oil capillary pressure was used to describe the imbibition cycle.

\[
p_{\text{cwp}}(S_w) = \alpha \ln \left( \frac{1 - S_{\text{wi}} - S_{\text{orw}}}{1 - S_w - S_{\text{orw}} + 0.0001} \right), \quad \text{for} \quad S_{\text{wi}} < S_w < 1 - S_{\text{orw}} \tag{8.10}
\]

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\[ p_{cw}(S_w) = \alpha_2 \ln \left( \frac{1 - S_{ow}}{1 - S_w - S_{wr} + 0.0001} \right), \quad \text{for} \quad S_{wr} < S_w < 1 - S_{ow} \quad [8.11] \]

The end point saturations \((S_{wr}, S_{ow})\) in three-phase relative permeability for matrix and fracture curves were honored (Table 5.6 and Table 5.9). To represent the capillary entry pressure for nano-size matrix pore, the capillary pressure between oil and water was calculated using the following equation for a 7.9 nm radius pore size (see Section 5.1.1 for pore size estimation):

\[ p_o - p_w = \frac{2\sigma_{ow} \cos \theta}{r} \quad [8.12] \]

Where \(p_o\) and \(p_w\) are oil and water phase pressures, \(\sigma_{ow}\) is the interfacial tension between oil and water phases, \(r\) is radius of curvature of the interface, and \(\theta\) is the contact angle. Bakken oil and water interfacial tension is 18.47 dyne/cm measured by a spinning drop IFT technique at 100 °C.

Wetting contact angle for preferentially oil wet rock is between 90° to 150° (Archer and Wall, 1986). Considering the preferentially oil-wet character of Middle Bakken, presented in Chapter 5, contact angle is assumed to be 100°. For a radius of 7.9 nm, the capillary pressure for matrix was calculated to be 585 psi. This number was used to calculate capillary pressure at irreducible water saturation for matrix. The shape of capillary pressure curves intended to represent oil-wet behavior for matrix with a small spontaneous water imbibition. Figure 8.22a displays the oil/water capillary pressure curve for matrix.

For fractures, spontaneous water imbibition is predicted to be the main mechanism without using a capillary pressure curve. Figure 8.22b plots the oil/water capillary pressure curve for fracture.

As mentioned previously, the injectivity of water at a high fixed pressure for 40-year may not be achievable both technically and economically. Therefore, the injection duration was reduced to 2.7 years in the new model. The water injection starts at day 450 until day 1450, then converted to a producer well. This model was also run with the predicted capillary pressure curves (Fig. 8.22).

Figure 8.23 compares the four heterogeneous model results including the previous waterflood model with 40-years of injection, waterflood model with 2.7-years of injection with and without capillary pressure curves against the primary depletion model.
Table 8.9 summarizes the results of each model displayed in Fig. 8.23.

- The model with 40-years of injection neglecting capillary pressure effect provided an incremental recovery of 0.92% at year 20.
- The model with 2.7-years of injection neglecting capillary pressure effect resulted in 0.36% more oil recovery than the base case.
- The 2.7-years of injection model with the inclusion of capillary pressure provided an incremental recovery of 0.26% at year 20.
<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary</td>
<td>No</td>
<td>--</td>
<td>--</td>
<td>326 MSTB</td>
<td>440 MSTB</td>
<td>3.88</td>
<td>5.24</td>
</tr>
<tr>
<td>Waterflood</td>
<td>No</td>
<td>40</td>
<td>1012.4</td>
<td>403 MSTB</td>
<td>534 MSTB</td>
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<tr>
<td>Waterflood</td>
<td>No</td>
<td>2.7</td>
<td>70.7</td>
<td>356 MSTB</td>
<td>475 MSTB</td>
<td>4.24</td>
<td>5.65</td>
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<tr>
<td>Waterflood</td>
<td>Yes</td>
<td>2.7</td>
<td>71.3</td>
<td>348 MSTB</td>
<td>456 MSTB</td>
<td>4.14</td>
<td>5.43</td>
</tr>
</tbody>
</table>

### 8.6 CO₂ Injection

The lower recovery with waterflooding due to its poor injectivity and high capillary pressure prompts us to evaluate CO₂ injection. The improved hydrocarbon recovery by various CO₂ models was investigated to understand the following impacts:

- Reservoir connectivity: homogenous versus heterogeneous models
- Well completion type: an injection well with 15-stage completion versus an open hole completion
- Injection scheme: injector/producer well pattern versus huff and puff injection

The three-well configuration and well spacing were kept identical as in the waterflood model. The three wells started production at a maximum oil rate of 700 BBL/D and a minimum pressure of 800 psi from day 1 to day 450. The center well was used as a CO₂ injection well.

In order to have a first contact miscibility of CO₂, the injection pressure of 8100 psi is maintained that is above the MMP and below the fracturing pressure. In the injector/producer well pattern, the center well with 15-stage frac completion was operated as a CO₂ injection well from day 450 to 1450. During this period, 100% mole of CO₂ was injected into the reservoir. Because both temperature and pressure are higher than the critical conditions of CO₂ (Chapter 5.2.4), it exists in the supercritical phase in the reservoir. From day 1450 to 1460, the well is stopped injection, letting CO₂ propagate and mix with oil in the reservoir. Then, the CO₂ injector was converted to an oil producer for the rest of the well life. The duration of injection was determined by capturing the produced amount of CO₂ from the producer wells. When total produced CO₂ amount was higher than injection amount, the injection stopped.
8.6.1 Effect of Reservoir Heterogeneity

Both homogenous model (Fig. 8.4) and the heterogeneous model (Fig. 8.5) were used to evaluate CO\textsubscript{2} injection. Figure 8.24 shows the pressure profile, the CO\textsubscript{2} mole fraction in oil, and oil viscosity after 2-years of injection in the homogenous model. The observations are summarized below:

- CO\textsubscript{2} injection creates a uniform pressure increase in the vicinity of the wellbore (Fig. 8.24a).
- CO\textsubscript{2} provides better injectivity and propagates more into the reservoir after 2-years of injection compared to water because it has a much lower viscosity than water. The distribution of CO\textsubscript{2} mole fraction in oil shows that CO\textsubscript{2} reaches both side wells after 2-year of injection via high conductive hydraulic fractures (Fig. 8.24b).
- CO\textsubscript{2} decreases oil viscosity following its flow path in the reservoir (Fig. 8.24c).

![](image)

**Figure 8.24**: Reservoir pressure, CO\textsubscript{2} mole fraction, and oil viscosity profiles after two years of CO\textsubscript{2} injection in the homogeneous model.

Figure 8.25 represents the side well oil production between primary depletion and CO\textsubscript{2} injection. The incremental oil was observed at around 650 days. The incremental oil recovery is 0.46% at year 20 with a CO\textsubscript{2} utilization of 5.1 MSCF/STB (MSCF of CO\textsubscript{2} per STB oil production). In the calculation of CO\textsubscript{2} utilization, the incremental oil from both side wells was included and the injection amount was calculated assuming the produced CO\textsubscript{2} was going to be recycled.
Figure 8.25: Primary depletion and CO$_2$ injection models: Comparison of a side well oil rate and cumulative oil production in the homogeneous model.

The heterogeneous model adapts the same production and injection strategy as that of the homogenous model. Figure 8.26 displays the same figures as in Fig. 8.24 but for the heterogeneous model.

- Poor CO$_2$ penetration and oil viscosity reduction were observed in the areas with less reservoir connectivity (Fig. 8.26a and Fig. 8.26b).
- The increased reservoir pressure was observed more at the toe and heel of the wellbore (Fig. 8.26a).
- CO₂ provides better injectivity and propagates more into the reservoir in the high-density fracture areas (Fig. 8.26b).
- Oil viscosity reduction occurs following the areas of CO₂ penetration (Fig. 8.29c).

**Figure 8.27** shows the side well oil production between primary depletion and CO₂ injection for the heterogeneous model. The incremental oil recovery is 0.36% at the end of CO₂ injection (day 1450) with a CO₂ utilization of 6.4 MSCF/STB. The incremental oil recovery is 0.41% at year 20 with a CO₂ utilization of 5.4 MSCF/STB.

![Figure 8.27: Primary depletion and CO₂ injection models: Comparison of a side well oil rate and cumulative oil production in the heterogeneous model.](image)

**Table 8.10** contrasts the homogenous versus heterogeneous model for the side well oil production under primary depletion and CO₂ injection.

**Table 8.10:** Summary of primary depletion and CO₂ injection model results for homogenous and heterogeneous models

<table>
<thead>
<tr>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Homogenous Model</td>
<td>Primary CO₂ Injection</td>
<td>--</td>
<td>354</td>
<td>480</td>
<td>4.21</td>
<td>5.71</td>
<td>--</td>
</tr>
<tr>
<td></td>
<td></td>
<td>386</td>
<td>392</td>
<td>518</td>
<td>4.67</td>
<td>6.17</td>
<td>5.1</td>
</tr>
<tr>
<td>Heterogeneous Model</td>
<td>Primary CO₂ Injection</td>
<td>--</td>
<td>326</td>
<td>440</td>
<td>3.88</td>
<td>5.24</td>
<td>--</td>
</tr>
<tr>
<td></td>
<td></td>
<td>384</td>
<td>360</td>
<td>481</td>
<td>4.29</td>
<td>5.73</td>
<td>5.4</td>
</tr>
</tbody>
</table>

The amount of incremental oil recovery and CO₂ injected volume were not substantially different between the homogenous and heterogeneous models because the main flow path for CO₂ was through the
hydraulic fractures. Therefore, a single stage open hole completion case for an injection well is further investigated in the following section.

8.6.2 Effect of Well Completion

The changing completion type for an injection well was an interest to observe the impact of an increase contact surface area of CO₂ on oil recovery. This scenario was simulated by converting CO₂ injection well from a 15-stage completion to an open hole completion using the heterogeneous model. In an open hole well completion, high conductive hydraulic fractures were taken out while maintaining the SRV enhanced permeability region.

Figure 8.28 shows the CO₂ distribution and oil viscosity after 2 years of injection for both scenarios. For the injection via open hole completion, CO₂ distributed along the horizontal wellbore due to an increased surface area and penetrated into the reservoir through micro-fractures. For the case with 15-stage frac completion, CO₂ followed the high conductive paths and reached the side wells.

Figure 8.29 compares the side well oil production for both models presented in Fig. 8.28 against the primary depletion. The incremental oil recovery at the end of CO₂ injection for an injection well with open-hole completion is 0.68% whereas it is 0.36% for an injection well with a 15-stage frac completion. The oil production was accelerated and increased with an open hole completion compared to multi-stage completion case.

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Figure 8.29: Primary depletion and CO₂ injection models with open hole and 15-stage frac well completion: Comparison of a side well oil rate and cumulative oil production in the heterogeneous model.

Table 8.11 tabulates the results from Fig. 8.29. Due to increased reservoir connectivity with an open hole completion, a better CO₂ penetration occurs with a 562 MMSCF of higher injection volume than 384 MMSCF in 15-stage frac injector model. This CO₂ utilization for both models is around 5.6 MSCF/STB. The more surface contact area of CO₂ with the reservoir the more oil is recovered.

In Section 8.4.2, it was shown that an increase in hydraulic fracture stages provided a higher ultimate recovery under primary depletion. However, this may be a concern in an injection/producer well pattern with a close well spacing because hydraulic fractures do not provide adequate surface contact area.

Table 8.11: Summary of primary depletion and CO₂ injection model results comparing 15-stage and open hole well completion for the injector

<table>
<thead>
<tr>
<th>Recovery Mechanism</th>
<th>Injector Completion Type</th>
<th>Injection Duration Day</th>
<th>Total Injected CO₂ MMSCF</th>
<th>P1 Well Cum. Prod. 20-year MSTB</th>
<th>Cum. Oil RF 20-year %</th>
<th>CO₂ Utilization 20-year MSCF/STB</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>326</td>
<td>3.88</td>
<td>--</td>
</tr>
<tr>
<td>CO₂ Injection</td>
<td>15-stage</td>
<td>1000</td>
<td>384</td>
<td>360</td>
<td>4.29</td>
<td>5.4</td>
</tr>
<tr>
<td>CO₂ Injection</td>
<td>open-hole</td>
<td>1000</td>
<td>562</td>
<td>376</td>
<td>4.48</td>
<td>5.7</td>
</tr>
</tbody>
</table>

8.6.3 Effect of Injection Scheme

The compositional heterogeneous model was used to investigate CO₂ huff and puff injection. The results are compared with the primary depletion and the CO₂ injector/producer well scheme models.
The three wells started production at maximum oil rate of 700 BBL/D and minimum pressure of 800 psi from day 1 to day 450. The center well was used as a CO₂ injection well.

In order to have a first contact miscibility, the injection pressure of 8100 psi is maintained that is above the MMP and below the fracturing pressure. In the injector/producer well pattern, the center well with 15-stage frac completion is operated as a CO₂ injection well from day 450 to 1450.

In the huff and puff model, three well started production at a maximum oil rate of 700 BBL/D and minimum pressure of 800 psi from day 1 to day 450 as in the previous models. At day 450, the center well started operating as a CO₂ injector for 60 days with a maximum injection rate of 1000 SCF/D. From day 60 to 70, injection was stopped, allowing CO₂ mixed with oil in the reservoir. From day 70 to day 190, the well was operated as a producer at a fixed pressure of 800 psi. The same CO₂ huff and puff steps were repeated for 6 cycles until day 1450. **Figure 8.30** demonstrates the CO₂ injection rate of the center well for both huff and puff (**Figure 8.30a**) and injector/producer (**Figure 8.30b**) models.

- In the huff and puff model, 1000 MSCF/D of CO₂ injection was achieved in all cycles except in the first cycle. The loss of injectivity in the first cycle was attributed to the minor depletion (i.e. high reservoir pressure) in the early stage of side wells production.
- In the injector/producer case, the injected CO₂ amount was driven by the void space. It started with 1000 MSCF/D and dropped to 600 MSCF/D within 150 days of injection. Once enough depletion took place in the reservoir, the injectivity of CO₂ was improved to 900 MSCF/D at the end of 1000 days of injection.

**Figure 8.30**: Heterogeneous Model: CO₂ injection rate.

**Figure 8.31** plots the oil rate and cumulative oil production of both models against primary depletion. The oil recovery with huff and puff was slightly improved from primary depletion, but much less than the recovery from that of injector/producer well case.
Figure 8.31: Primary depletion and CO₂ injection models with injector/producer and huff and puff approach: Comparison of oil rate and cumulative oil production in the heterogeneous model.

Table 8.12 summarizes the results from Fig. 8.31. The incremental oil recovery at year 20 for CO₂ huff and puff model is 0.11% after 6-cycle of injection and it is 0.41% for the injector/producer well pattern. The injected CO₂ amount after recycling is 314 MMSCF for the huff and puff model and 384 MMSCF for the injector/producer well pattern. Therefore, in the huff and puff model a higher CO₂ utilization of 33.7 MSCF/STB was obtained than that of 5.4 MSCF/STB in injector/producer well pattern model. This suggests a poor efficiency in CO₂ huff and puff injection over continuous injection. Because CO₂ via huff and puff process does not have enough time to mix with oil, penetrate into the reservoir to facilitate side oil wells’ production, or provide enough pressure increase.

Table 8.12: Summary of primary depletion and CO₂ injection model results comparing huff and puff injection with continuous injection

<table>
<thead>
<tr>
<th>Recovery Mechanism</th>
<th>Injector Completion Type</th>
<th>Total Injection Duration Day</th>
<th>Total Injected CO₂ MMSCF</th>
<th>P1 Well Cum. Prod. 20-year MSTB</th>
<th>40-year MSTB</th>
<th>Cum. Oil RF 20-year %</th>
<th>40-year %</th>
<th>CO₂ Utilization 20-year MSCF/STB</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>326</td>
<td>440</td>
<td>3.88</td>
<td>5.24</td>
<td>--</td>
</tr>
<tr>
<td>CO₂ Injection</td>
<td>15-stage</td>
<td>1000</td>
<td>384</td>
<td>360</td>
<td>481</td>
<td>4.29</td>
<td>5.73</td>
<td>5.4</td>
</tr>
<tr>
<td>CO₂ Huff &amp; Puff</td>
<td>15-stage</td>
<td>360</td>
<td>314</td>
<td>335</td>
<td>456</td>
<td>3.99</td>
<td>5.43</td>
<td>33.7</td>
</tr>
</tbody>
</table>

In the current model, the flow mechanism was captured only with pressure differential, but not with molecular diffusivity due to numerical convergence issues in the full scale model. Diffusion of gas component within the oil phase may improve the recovery from matrix. During this slow mechanism, duration of soak period may play a significant role for diffusion to take place between matrix and
fractures in the dual porosity media. However, the diffusivity coefficient for CO\(_2\) in oil phase for ultra-tight formation is not known with our current knowledge. Therefore, it is not included in this research.

8.5 Well Spacing

Well spacing is one of the key factors when optimizing hydrocarbon production during both primary recovery and EOR processes. Therefore, a further study was deployed to investigate the optimum well spacing for the primary depletion and CO\(_2\) injection. Due to numerical convergence and CPU runtime issues, a hydraulic fracture sector model was built to simulate 330, 660, and 1320 ft of well spacing. A homogenous model with three wells was used so that a single-frac model can be scale-up to a full-scale model.

**Figure 8.32** shows schematic of full scale and two single-frac models: a full-scale base model presented earlier (Fig. 8.32a), an end-frac model to capture the hydraulic fractures close to toe and heel of the wellbore (Fig. 8.32b), a mid-frac model to represent a hydraulic fracture within two hydraulic fractures (Fig. 8.32c).

Scale-up took the following form: the oil recovery from the end-frac model was multiplied by 2 and the recovery from the mid-frac model was multiplied by 13 because full scale model has a total of 15-stage frac.

Previously presented homogeneous full-scale model with 660 ft well spacing (listed in Table 5.8) was used to create the single-frac sector models. The wells are operated at the same pressure in each sector model. The total maximum rate was divided by 15 to calculate a flux for each hydraulic fracture.

**Figure 8.32**: Schematic of sector modeling including full-scale model, end-frac sector model, and mid-frac sector model.
Figure 8.33 shows the cumulative oil production profile for a full-scale, end-frac, and mid-frac models. The EUR values from the full-scale and sector models with their scale-up values were also included in Fig. 8.33. There is a good agreement between the full-scale and scale-up model results. This supports our approach to use sector models when evaluating the effect of well spacing.

<table>
<thead>
<tr>
<th>Model Type</th>
<th>Mid-HF Production MSTB</th>
<th>End-HF Production MSTB</th>
<th>EUR MSTB</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full Scale</td>
<td>--</td>
<td>--</td>
<td>480.6</td>
</tr>
<tr>
<td>Hydraulic Fracture</td>
<td>31.2</td>
<td>37.5</td>
<td></td>
</tr>
<tr>
<td>Scale-up</td>
<td>405.6</td>
<td>75.0</td>
<td>480.6</td>
</tr>
</tbody>
</table>

Figure 8.33: Cumulative production plots for full-scale, end-frac, and mid-frac models (HF stands for hydraulic fracture) and summary of results.

Besides the 660 ft well spacing, 330 and 1320 ft well spacing models were also studied (Fig. 8.34). The hydraulic fracture half-length of 160 ft and injection scheme were identical as in the base model (Section 8.5).

Figure 8.34: Schematic of mid-frac model with 330, 660, and 1320 ft well spacing.

Figure 8.35 shows the scale-up oil rate and cumulative production plots for the primary depletion model. In the early time of well production, 330 ft well spacing provided a higher initial rate because the SRV of each well overlapped. Following this accelerated depletion, the wells shown a sharp decline due
to interference effect. For 660 and 1320 ft well spacing, the wells started producing with a similar decline. In the long term a well interference occurred slightly earlier in 660 ft spacing model than 1320 ft spacing model. At year 20, 1320 ft well spacing scenario produced 42,000 STB of more oil (incremental oil recovery of 0.5%) than that from 660 ft well spacing case. Thus, in terms of technically recoverable hydrocarbon, 1320 ft may be the optimum well spacing for primary depletion. Operationally, this decision may change due to its economic feasibility over 330 and 660 ft spacing.

**Figure 8.35:** Primary depletion with 330, 660, and 1320 ft well spacing including three wells.

**Figure 8.36** shows the same plot as in Fig. 8.35 for CO₂ injection model. The EUR from the full scale CO₂ injection was compared against the scale-up model (Table 8.12).

In the 330 ft spacing model, once CO₂ injection started, a breakthrough occurred through hydraulic fractures. Due to the near-wellbore pressure increase, the production remains stabilized during the injection period. Once the injection stopped, a sharp production decline was observed.

**Figure 8.36:** CO₂ injection with 330, 660, and 1320 ft well spacing including three wells.

In 660 ft well spacing model, incremental oil was observed around 600 days. In 1320 ft well spacing model, there was no impact on side well oil production by CO₂ injection because of the long
distance between the injector and producer. A higher production in the long-term for 1320 ft well spacing case is because there is no well interference effect as discussed in the primary depletion model. In other words, this was not attributed to the CO₂ injection. Based on the CO₂ injection result, 660 ft may be the optimum well spacing for in a CO₂ injection for Bakken.

Table 8.13 summarizes the model EUR and incremental recovery for both primary depletion and CO₂ injection models. For primary depletion, the highest ultimate oil recovery was obtained with 1320 ft well spacing. For CO₂ injection, the highest incremental recovery of 0.46 % was obtained with the 660 ft well spacing.

Table 8.13: Summary of well spacing models for primary depletion and CO₂ injection (HF stands for hydraulic fracture)

<table>
<thead>
<tr>
<th>Recovery Mechanism</th>
<th>Well Spacing ft</th>
<th>Model Type</th>
<th>Mid-HF Production MSTB</th>
<th>End-HF Production MSTB</th>
<th>EUR Oil 20-year MSTB</th>
<th>Cum. Oil RF %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary</td>
<td>330</td>
<td>Single HF Model Scale-up Model</td>
<td>22.2 288.0</td>
<td>25.4 50.7</td>
<td>339</td>
<td>4.04</td>
</tr>
<tr>
<td>CO₂ Injection</td>
<td>330</td>
<td>Single HF Model Scale-up Model</td>
<td>23.4 304.1</td>
<td>26.5 53.0</td>
<td>357</td>
<td>4.25</td>
</tr>
<tr>
<td>Primary</td>
<td>660</td>
<td>Single HF Model Scale-up Model</td>
<td>23.1 300.8</td>
<td>26.6 53.2</td>
<td>354</td>
<td>4.21</td>
</tr>
<tr>
<td>CO₂ Injection</td>
<td>660</td>
<td>Single HF Model Scale-up Model</td>
<td>25.7 334.2</td>
<td>29.1 58.2</td>
<td>392</td>
<td>4.67</td>
</tr>
<tr>
<td>Primary</td>
<td>1320</td>
<td>Single HF Model Scale-up Model</td>
<td>25.9 336.1</td>
<td>29.8 59.6</td>
<td>396</td>
<td>4.71</td>
</tr>
<tr>
<td>CO₂ Injection</td>
<td>1320</td>
<td>Single HF Model Scale-up Model</td>
<td>25.9 336.8</td>
<td>29.8 59.7</td>
<td>397</td>
<td>4.73</td>
</tr>
</tbody>
</table>
CHAPTER 9

CONCLUSIONS, DISCUSSION AND RECOMMENDATIONS

This chapter summarizes the key discoveries for each chapter, and provides the contributions and conclusions of the thesis. We first present the overall conclusions of the thesis, next we present a discussion on the topics covered by the thesis, third we present the chapter summaries and key discoveries, and finally we present a set of recommendations for future studies in support of enhanced oil recovery in Bakken.

9.1. Conclusions

1. The difference in the magnitude of core-measured permeability \((10^{-4}-10^{-5} \text{ md})\) and field-measured permeability \((10^{-1}-10^{-2} \text{ md})\) suggests that, in addition to matrix porosity, a microfracture network is present in Bakken and is the main reason for facilitating oil production from Bakken formation. Furthermore, in pursuit of enhanced oil production, the micro-fracture network is the main pathway for delivering water or CO\(_2\) to the tight matrix of the Bakken formation.

2. Dual-porosity modeling is the prudent approach for simulating primary production and improved oil recovery from Bakken because of the flow hierarchy; that is, flow from matrix to microfracture and microfracture network, then to the multi-stage hydraulic fractures, and eventually to the horizontal wellbore. A single-porosity model, consisting of matrix connecting to multi-stage hydraulic fractures and the wellbore, is insufficient to match well performance without including contributions from the micro and macro fracture network.

3. Time analysis of flow and pressure over the history of a well, supplemented by the pressure and rate transient analysis of shorter-duration well tests, provides the most important flow characterization data to be used in reservoir modeling. However, detailed geologic reservoir characterization is the most crucial early information needed to develop a representative flow model. In fact, in this thesis, geologic reservoir characterization was an integral part of the reservoir model construction for production analysis and forecasting.

4. In addition to geologic reservoir characterization, and pressure and rate analysis of wells, laboratory flow experiments were conducted to determine the basic core properties (porosity, permeability, wettability, pore size, mineralogy, etc.). Then, specific laboratory tests were conducted to determine the potential for enhanced oil recovery using salinity brines and CO\(_2\). The
latter experiments suggested that such injectants only recover oil from a thin outer layer of the matrix by counter-current flow and not by the conventional oil displacement process.

5. The numerical modeling indicates that CO₂ injection via injector-producer well patterns can enhance oil production but, for economic viability, recycling of the produced CO₂ is necessary. Oil production by CO₂ injection is higher than by waterflooding, but field pilot tests are needed before a major field project is implemented.

9.2. Discussion

Forecasting oil production by primary depletion and any EOR processes in Bakken require field specific evaluations due to the differences in the reservoir and fluid properties of the Bakken fields in Williston Basin. The research conclusions of this thesis pertain to Bakken fields in North Dakota.

The order of magnitude difference between core-measured permeability (10⁻⁴-10⁻⁵ md) and field-measured permeability (10⁻¹-10⁻² md) suggests contribution of a micro-fracture system to the productivity of Bakken Formation. The implication of the presence of a micro-fracture network is the main reason to explore application of waterflooding and CO₂ injection in the Bakken Formation to enhance oil production.

The formation characterization via mini-DST, mini-frac, and long pressure buildup tests not only help to understand the effective formation permeability but also help to determine the best completion and stimulation technique.

Petrographic analysis is needed to characterize rock texture, mineral composition, micro-fracture network, pore structure, hydrocarbon storage, and oil, water, and gas samples are needed for thermodynamic property evaluation and understanding fluid flow in matrix nanopores and micro-fracture network.

The dual-porosity modeling is the preferable option for both primary and EOR applications than single-porosity modeling because of the inherent flow hierarchy.

In primary depletion, creating a larger SRV by increasing the fracture network between hydraulic fractures is the key driver to higher oil production. The incremental oil production in waterflooding should also be attributed to the fracture network for providing the conduit for oil to be produced.

Low salinity brine could be considered an EOR fluid because Middle Bakken Formation imbibes low-salinity brine either by capillary action or by osmotic pressure. Although fluid drop experiments, presented earlier, show that Middle Bakken is preferentially oil-wet, the imbibition of low salinity brine could be attributed to the presence of clays.
Although the incremental recovery with CO\textsubscript{2} injection is only slightly higher than that in waterflooding, CO\textsubscript{2} injectivity is more favorable. Furthermore, CO\textsubscript{2} pilot should be located in an area of high micro-fracture intensity while avoiding the fracture corridors and faults because those geologic features can cause pre-mature CO\textsubscript{2} breakthrough.

Each oil recovery scheme requires different considerations for well spacing and well completion type. For instance, in depletion, a well spacing of 1320 ft with a 30-stage frac well completion provides a bigger hydrocarbon recovery than that with a well spacing of 660 ft and a 15-stage frac completion. In CO\textsubscript{2} huff-and-puff process, microfracture presence in the vicinity of the wellbore provides CO\textsubscript{2} flow path to the reservoir as well as hydrocarbon flow back to the wellbore.

9.3. Chapter Summaries and Key Discoveries

This section summarizes key discoveries in five categories, which include geology, reservoir fluid properties, rock properties, well testing, rate transient analysis, and numerical modeling.

CHAPTER 3 describes the geology of Bakken including petrophysical properties, petro-facies, and petroleum system. The followings summarize the key results of this chapter:

- The hydrocarbon-bearing formations that have production potential in North Dakota include Lodgepole, Scallion, Middle Bakken, and Three Forks formations.
- The hydrocarbon source rock for the Bakken includes the organic rich Lower and Upper Bakken shale units, where the TOC content ranges from 12 to 36 weight percent. The Middle Bakken is organic poor, with TOC ranging from 0.1 to 0.3 weight percent. Because of the high organic content in the Upper and Lower Bakken shale, both gamma ray and resistivity responses are high. In contrast, the pore space in the Middle Bakken is partially filled with high salinity formation brine resulting in low resistivity.
- The petrographic analyses of three Bakken wells in Bailey field showed that Middle Bakken has five lithofacies. The laminated MB3 facies is often the drilling target for horizontal wells.
- Lodgepole in North Dakota has higher water saturation than in Scallion, Middle Bakken, and Upper Three Forks based on the petrophysical properties.
- The Lodgepole Formation exhibits a rapid decline in oil flow rate, high water-oil cut, and gas-oil ratio. Cores and mini-frac test suggest the presence of abundant stress-dependent fractures. Thus, Lodgepole development is economically questionable.
- The Scallion Formation has a high water saturation but better porosity and more movable oil than Lodgepole in a naturally fractured system. Thus, developing Scallion formation may require only a small number of multi-stage completions or vertical wells.
- The Middle Bakken Formation has a high initial pressure and is overpressure in nature, therefore, it has a better oil productivity potential than Lodgepole and Scallion formations. Oil production from Middle Bakken formation can be enhanced with advanced completion technology and enhanced oil recovery schemes.

- The Upper Three Forks Formation has lower water saturation (mostly irreducible) and higher porosity than the Middle Bakken Formation. In the research area, the Upper Three Forks wells have equal or better production performance in comparison with the Middle Bakken wells.

- The petrophysical and petro-facies differences between the Bakken in Elm Coulee Field, Montana, and Bakken fields in North Dakota show the formation is more oil wet in Elm Coulee.

**CHAPTER 4** summarizes the *reservoir fluid properties* of Middle Bakken Formation in Reunion Bay, Bailey and Murphy Creek fields. A summary of the key results follow:

- The initial reservoir oil is undersaturated, and the average bubble point pressure and solution gas-oil ratio for the Middle Bakken fluid samples decrease from 2400 to 1500 psi and 870 to 460 SCF/STB in Reunion Bay (North-East) to Murphy Creek (South-West), respectively.

- All the recombined oil samples are dominated by low molecular weight components and minor amounts of nitrogen, carbon dioxide, and hydrogen sulfide.

- The saturate to aromatic ratio of the Middle Bakken reservoir crude lies below the stable region, indicating a low risk of asphaltene precipitation during primary depletion.

- The water content in the crude is also low which indicates a lower risk of corrosion.

- The reservoir water samples from the Middle Bakken and Three Forks have an average TDS of 285,000 mg/L with a pH of 5.7. In contrast to this very saline water, the fracturing fluid currently used in the study area during the stimulation is very low saline water with less than 5000 mg/L of TDS.

- Miscible CO\textsubscript{2} injection can be achieved in the Bakken due to high reservoir pressure and minimum miscibility pressure of 3300 psi that was obtained by a Rising Bubble Apparatus test.

- Approximately 190 SCF of CO\textsubscript{2} is lost per STB of water at reservoir pressure of 7800 psi and a reservoir temperature of 240°C. Thus, CO\textsubscript{2} loss due to solubility in water can be significant in Bakken.

- Lab measured CO\textsubscript{2} swelling and viscosity measurements are required to tune EOS parameters when modeling CO\textsubscript{2} injection via compositional simulation.

**CHAPTER 5** describes the *rock properties* of Middle Bakken Formation including both static core characterization and dynamic flow measurements. The key results of this chapter follow:
- The proposed steady-state method is more reliable than other plug-based measurements since it depends on flow rate or velocity of fluid if a constant pressure drop is applied rather than measuring pressure response at one end of the sample.
- Even in the case of ultra-low permeability samples, supercritical CO₂ achieves a steady-state within a short time (2-3 days) due to its low compressibility; in contrast it can take months using kerosene to obtain a single point of permeability measurement.
- The supercritical CO₂ method eliminates the use of standard core extraction and re-saturation protocol and its low viscosity enables measuring flow rate and pressure gradients.
- The proposed CO₂ steady-state permeability experiment is conducted at high pressure, representing effective reservoir stress, and high temperature to provide supercritical and miscible condition for CO₂.
- There are three primary rock textures observed in the target laminated facies zone. The mineralogy of these rock types and the average core permeability and unstressed gas filled porosity are listed below:
  - Sandstone with pore-filling calcite cement (0.00001 md and 1.3%)
  - Argillaceous sandstone with pore-filling clays (0.0001 md and 3.3%)
  - Dolomitic to variably calcareous, argillaceous, slightly sandy siltstone (0.001 md and 5.7%)
- Both matrix and fracture permeability is reduced as a function of increasing effective stress. Also, matrix permeability does not recover with restoration of initial stress.
- The samples with visible micro-fractures have an order of magnitude higher permeability.
- The micro-fracture aperture for various Middle Bakken lithofacies measures between 2.4 and 17µm.
- The fracture orientation displays a dominant NE to ENE trend in the Williston Basin.
- Although the Middle Bakken is preferentially oil-wet, low salinity brine imbibition takes place in the pores that are clay-filled.
- The majority of the porosity in the Middle Bakken is micro-porosity associated with detrital clay-filled, irregularly shaped or slot-like pores. These pores are connected through laminations and micro-fractures.
- The core samples with visible laminations associated with clay filled pores show a greater spontaneous imbibition with low salinity brine several days after the experiment.
- The high pressure and temperature spontaneous imbibition shows the potential for additional oil recovery with CO₂ after producing through low salinity brine system.
- High reservoir formation salinity, clay content being primarily illite, and crude properties (e.g. TAN, TBN) promote the use of low salinity brine in the Bakken as a frac fluid or an EOR fluid type.
- The success with low salinity brine frac fluid may be explained due to the osmotic effect, local pH value increase near the clay surface, and ionic double layer effect.
- The poor water imbibition in a high salinity brine may be due to the decrease in the size of the ionic double layer between the clay and oil interfaces thus promotes oil-wet behavior.

**CHAPTER 6** discusses about the **pressure transient test** applications in unconventional reservoirs by showing the Bakken examples. The key results are:
- Reservoir permeability in unconventional reservoirs can be quantified by several different flow tests which include mini-DST, mini-frac, and long-pressure buildup.
- Mini-DST application in unconventional reservoirs is a new innovation first applied in Bakken Formation to obtain pressure transient data from an open-hole section of a vertical well. Such data is used to estimate formation flow capacity of different reservoir intervals in the same formation to identify the optimal location for well completion.
- Mini-frac test helps determine the fracture properties and leakoff mechanism. This information for the Scallion mini-frac test indicates high intensity pressure-dependent fractures, lower reservoir pressure, and higher permeability than those analyzed from the Middle Bakken mini-frac test.
- The long-pressure buildup test for unconventional to provide an effective permeability of the total system that can be compared against a core matrix permeability measurement. Having pressure buildup test for both pre- and post-hydraulic fracture stimulation provides insights about the effective permeability and well flow regimes due to the hydraulic fractures.
- In the Bakken based on the formation permeability:
  - Mini-DST test may exhibit radial and/or spherical flow
  - Mini-frac may exhibit linear and/or radial flow
  - Long pressure buildup may show a bilinear flow regime for an unfractured well, linear flow for a fractured horizontal well and a fractured vertical well, and radial flow for the well with the abundance of natural fractures.
- The closed-form solutions of each flow regime can be used to calculate effective permeability with the integration of fluid and rock properties.

**CHAPTER 7** presents the application of **rate transient analysis** and introduces both single- and multi-phase flow equations to analyze well production data. The key results are:
- Production history of unconventional reservoirs exhibits a hyperbolic decline rather than an exponential decline of conventional reservoirs.
- There are several key drivers impacting well production including well configuration, well completion and stimulation, and geology.
- Comparing Bakken in North Dakota, Elm Coulee in Montana has an order of magnitude higher matrix permeability, higher fracture intensity, lower initial reservoir pressure, and higher porosity.
- The decrease in slope of Arps decline exponent $b$ is a measurement of reservoir heterogeneity, loss of pore volume connectivity (reservoir production conformance) and/or pore volume compartmentalization away from the wellbore.
- The increasing Arps flow rate exponent $b$ with completion year may be attributed to an increase of reservoir connectivity as a result of improved completion technology with the multi-stage method.
- A vertical well producing over twenty years from the Upper Bakken Shale suggests a persistent flow contribution from matrix.
- Historical well data shows a production increase from vertical wells to short laterals, short laterals to long laterals, and single-stage completion to multi-stage completion.
- Wells with multi-stage completions tend to have higher effective permeabilities. This indicates an increased flow capacity with multi-stage completion.
- The effective permeability distribution reveals that Reunion Bay has higher reservoir connectivity than Bailey and Murphy Creek. Bailey has better reservoir connectivity compared to Murphy Creek.
- The single-phase flow equation can be used to calculate effective permeability whereas multi-phase flow provides a sum of all mobile phases’ transmissibilities. The transmissibility for each phase can be then calculated using the production data.
- The effectiveness of the completion technique and geological differences on production can be identified using linear flow analyses.
- The flow regimes, including linear, transition, and pseudo boundary, can be used to identify Arps flow rate exponent $b$ from log-log scale of rate versus material balance time.
- The Cartesian plot of normalized pressure versus actual time is used to decipher the reasons for having different well performance behavior of wells and determine effective permeability.
- The log-log plot of normalized pressure versus material balance time is used to diagnose flow regimes.
- The log-log pressure and pressure derivative versus material balance time plot is also used to identify flow regime from the well production data.

**CHAPTER 8** presents the workflow to integrate the geological description of the Bakken Formation into a **multi-layer compositional dual-porosity simulation model** so that the well performance can be evaluated under primary depletion, waterflooding, and CO₂ injection. The results are summarized as:

- A multi-layer dual porosity compositional reservoir simulation model was built to integrate the geological description of the Bakken Formation. History-matching of production data from a hydraulically fractured horizontal well in Middle Bakken was performed.
- Fine logarithmic gridding is required to capture transient flow in unconventional reservoirs.
- A dual porosity model is more reliable because of the inherent flow hierarchy controls compared to a single-porosity model.
- A single-porosity system, based on matrix core permeability alone, is insufficient to validate well performance without additional contributions from micro and macro fractures.
- During the history-match the simulation model should be calibrated by analyzing well drawdown data and pressure buildup data. This helps reduce the uncertainty in fracture spacing and SRV dimension.
- During the forecast the decline behavior of the well flow rate from the simulation model should be compared against the empirical rate-time plots and diagnostic pressure and rate plots.
- Well recovery increases with increasing SRV for both vertically and horizontally.
- Increase of completion stages results in a higher oil recovery. However, after 30 stages, the oil recovery does not provide as much as recovery compared to the amount of increase from 8-stage to 15-stage because the Middle Bakken Formation already has micro-fractures.
- A geologically characterized model with various fracture spacing is required to evaluate the impact of reservoir heterogeneity on waterflooding and CO₂ injection.
- The incremental oil recovery in waterflooding is attributed to the micro-fractures which are also a key driver for primary production.
- During waterflood, achieving a high injection pressure requires more powerful surface compression.
- The incremental oil recovery in waterflooding reduces by including capillary pressure curves in the simulation model due to an excess capillary pressure resistance in nano-size matrix pores.
- The incremental oil recovery and injected CO$_2$ amount are not substantially different between the homogenous and heterogeneous models because the main flow path for CO$_2$ is through the hydraulic fractures.
- During CO$_2$ injection increased contact surface area due to increase of micro-fracture intensity is important to enhance oil production.
- The CO$_2$ injector well with an openhole single-stage well completion provides a better injectivity and more surface contact area of CO$_2$ via micro-fractures than that from the multi-stage completion via hydraulic fractures.
- During CO$_2$ injection high conductive hydraulic fractures as well as regional faults may cause an early breakthrough because of inadequate surface contact.
- Assuming the produced CO$_2$ is recycled, the CO$_2$ utilization is around 5.6 MSCF/STB (MSCF of CO$_2$ per STB oil production) for the injector/producer case in the heterogenous model and 33 MSCF/STB for the huff and puff injection.
- CO$_2$ huff and puff suggests a poor efficiency over continuous injection. This is because CO$_2$ via huff and puff does not have enough time to mix with oil, penetrate into the reservoir to facilitate side oil wells’ production, or provide enough pressure increase.
- In the heterogeneous model, natural depletion, continuous CO$_2$ injection, and waterflooding yield cumulative recovery factors of 5.24, 5.65, and 5.81% of the original oil in place for the Middle Bakken Formation.
- To overcome numerical convergence and CPU runtime, a single hydraulic fracture model can be used and scale-up to a full field model when evaluating the effect of well spacing.
- For primary depletion, the highest ultimate oil recovery is obtained with a well spacing of 1320 ft.
- For CO$_2$ injection, the highest incremental recovery is obtained with a well spacing of 660 ft.

9.4. Recommendations

The following recommendations pertain to potential areas for improving the reservoir characterization of the Bakken under primary depletion, waterflood, and CO$_2$ injection.
- The experimental work presented in this research can be extended to CO$_2$, low salinity brine, and carbonated brine. The interpretation and analysis of such experiments should include fluid-fluid and fluid-rock interaction as well as flow mechanisms.
- More experiments should be conducted to have a better understanding of low salinity brine in oil recovery. For example, the pH value and wettability index should be quantified for a sequence of experiments with various salinities.
- Similar to conventional CO₂ injection, the unconventional incremental oil recovery by CO₂ should be related to the pore volume of CO₂ injected.
- Quantitative ways to measure oil droplets residing on the core surface should be investigated.
- Surfactant flooding should also be studied as an EOR alternative for unconventional reservoirs. Experimental studies should include fluid-fluid and rock-fluid interactions, wettability alteration and IFT reduction.
- Pressure and rate transient analysis should be extended to multiple layers.
- Multi-phase rate transient analysis should be extended from natural lift operations to pump production. In addition, the effect of pump installation-timing and pressure drawdown should be investigated to optimize production.
- The simulation model can be extended to include the hydrocarbon-bearing formations above and below Bakken to assess additional oil recovery.
- In larger scale field modeling, it was difficult to accommodate diffusion in the model because of numerical instability and the prevailing numerical dispersion effects. Measuring CO₂ diffusivity coefficient into the oil phase in unconventional reservoirs is also recommended. Such data can be used to investigate the impact of CO₂ diffusion on oil recovery in dual-porosity compositional reservoir modeling.
NOMENCLATURE

Unit of Measurement Abbreviations

- **BBL**: barrel
- **cp**: centipoise
- **D**: day
- **ft**: feet
- **K**: Kelvin temperature
- **md**: millidarcy
- **mol**: mole
- **ppm**: parts per million
- **psi**: pound per square inch
- **RB**: reservoir barrel
- **STB**: stock tank barrel

Symbols

- \( a_{\text{fracture}} \): water activity in fractures
- \( a_{\text{matrix}} \): water activity inside the matrix pores
- \( A \): cross-section area, \( L^2 \) (cm\(^2\), ft\(^2\))
- \( A_c \): acentric factor
- \( b \): Arps decline exponent
- \( b_k \): Klinkenberg coefficient
- \( B \): formation volume factor, \( L^3/L^3 \) (RB/STB)
- \( B_f \): formation volume factor for each phase, \( L^3/L^3 \) (RB/STB)
- \( B_g \): gas formation volume factor, \( L^3/L^3 \) (RCF/SCF)
- \( B_o \): oil formation volume factor, \( L^3/L^3 \) (RB/STB)
- \( B_w \): water formation volume factor, \( L^3/L^3 \) (RB/STB)
- \( c \): Peneloux volume-shift factor
- \( c_f \): fluid compressibility, \( L^2F^{-1} \) (1/psi)
- \( c_{t,m} \): total matrix compressibility, \( L^2F^{-1} \) (1/psi)
- \( c_{t,f} \): total fracture compressibility, \( L^2F^{-1} \) (1/psi)
- \( c_t \): total reservoir compressibility, \( L^2F^{-1} \) (1/psi)
- \( C_T \): total leakoff coefficient
- \( C_{sp} \): equivalent NaCl concentration, (ppm)
- \( C_{si} \): concentration of each ion, (ppm)
\( D \): Arps decline rate
\( D_i \): initial decline constant for hyperbolic rate relation
\( D_{\text{min}} \): terminal decline rate, \( \% \)
\( F_{cd} \): fracture conductivity (dimensionless)
\( F_R \): radial flow time function, dimensionless
\( F_L \): linear flow time function, dimensionless
\( g \): loss-volume function, dimensionless
\( g_0 \): initial loss-volume function, dimensionless
\( G \): G-function, dimensionless
\( h \): formation thickness, \( L \) (ft)
\( h_w \): tested interval between packers, \( L \) (ft)
\( J \): productivity index, \( L^5 P^{-1} t \) (BBL/D/psi)
\( k \): permeability, \( L^2 \) (md)
\( k_a \): absolute permeability, \( L^2 \) (md)
\( k_B \): Boltzmann constant
\( k_{eff} \): effective permeability, \( L^2 \) (md)
\( k_f \): fracture permeability, \( L^2 \) (md)
\( k_{f,eff} \): effective fracture permeability, \( L^2 \) (md)
\( k_g \): apparent gas permeability, \( L^2 \) (md)
\( k_{hf} \): hydraulic fracture permeability, \( L^2 \) (md)
\( k_{gas} \): gas permeability, \( L^2 \) (md)
\( k_{liquid} \): liquid permeability, \( L^2 \) (md)
\( k_m \): matrix permeability, \( L^2 \) (md)
\( K_n \): Knudsen number (dimensionless)
\( k_{ro} \): oil relative permeability
\( k_{rw} \): water relative permeability
\( k_{rg} \): gas relative permeability
\( k_r \): radial horizontal permeability, \( L^2 \) (md)
\( k_x \): permeability in x-direction, \( L^2 \) (md)
\( k_y \): permeability in y-direction, \( L^2 \) (md)
\( k_s \): damaged zone permeability, \( L^2 \) (md)
\( k_{sp} \): spherical permeability, product of horizontal and vertical permeability, \( L^2 \) (md)
\( k^*_w \): water relative permeability end-point
\( k^*_r \): oil relative permeability end-point
\( k_{rg}^* \): gas relative permeability end-point
\( k_z \): permeability in z-direction, \( L^2 \) (md)
\( k_v \): radial horizontal permeability, \( L^2 \) (md)
\( L \): length, \( L \) (ft)
\( L_{x,y,z} \): dimensions of a rectangular parallel-piped matrix block, \( L \) (ft)
\( M \): weighting factor
\( m \): initial weight, \( m \) (g, lb)
\( m_L \): slope of data on pseudo-linear flow graph, \( FL^{-2} \) (psia)
\( m_r \): slope of radial flow, \( FL^{-2} t^{-1/2} \) (psi/log cycle)
\( m_R \): slope of data on pseudo-radial flow graph, \( FL^{-2} \) (psia)
\( m_{i/4} \): slope of bilinear flow, \( FL^{-2} t^{-1/4} \) (psi/hr^{1/4})
\( m_{i/2} \): slope of linear flow, \( FL^{-2} t^{-1/2} \) (psi/hr^{1/2})
\( m_{sp} \): slope of spherical flow, \( FL^{-2} t^{-1/2} \) (psi/hr^{1/2})
\( n_f \): total number of fractures
\( n_l \): Corey exponent for liquid
\( n_g \): Corey exponent for gas
\( n_o \): Corey exponent for oil
\( n_w \): Corey exponent for water
\( q \): oil production rate, \( L^3 t^{-1} \) (cc/s, BBL/D)
\( q_f \): flow rate for each phase, \( L^3 t^{-1} \) (BBL/D)
\( q_i \): initial oil production rate, \( L^3 t^{-1} \) (BBL/D)
\( q_g \): gas production rate, \( L^3 t^{-1} \) (SCF/D)
\( q_o \): oil production rate, \( L^3 t^{-1} \) (BBL/D)
\( q_w \): water production rate, \( L^3 t^{-1} \) (BBL/D)
\( q_t \): formation volume factor, \( L^3 t^{-1} \) (BBL/D)
\( Q \): cumulative production, \( L^3 \) (bbl)
\( r \): radius of curvature of the gas-oil interface, \( L \) (nm)
\( r_{inv} \): radius of investigation, \( L \) (ft)
\( P \): pressure, \( FL^{-2} \) (psi)
\( P_c \): critical pressure, \( FL^{-2} \) (psi)
\( p_{cwo} \): capillary pressure between oil-water, \( FL^{-2} \) (psi)
\( p_f \): fracture pressure, \( FL^{-2} \) (psi)
\( P_f \): final pressure, \( FL^{-2} \) (psi)
\( p_g \): gas phase pressure, \( FL^{-2} \) (psi)
\( p_i \): initial reservoir pressure, FL\(^{-2}\) (psi)
\( p_m \): matrix pressure, FL\(^{-2}\) (psi)
\( \overline{P} \): mean pore pressure, FL\(^{-2}\) (psi)
\( p_o \): oil phase pressure, FL\(^{-2}\) (psi)
\( p_{osm} \): formation volume factor, L\(^3\)/L\(^3\) (RB/STB)
\( p_{uf} \): upstream pressure, FL\(^{-2}\) (psi)
\( p_{ws} \): well static pressure, FL\(^{-2}\) (psi)
\( S \): skin factor
\( S_{hf} \): apparent skin
\( S_l \): liquid saturation, (fraction)
\( S_{or} \): irreducible oil saturation, (fraction)
\( S_w \): water saturation, (fraction)
\( S_{wi} \): initial water saturation, (fraction)
\( r_s \): radius of damaged zone, L (ft)
\( r_w \): wellbore radius, L (ft)
\( R \): universal gas constant, (kg-mol.K\(^{-1}\))
\( R_w \): resistivity of formation, mL\(^3\)tq\(^2\)
\( t \): shutin time for buildup, the elapsed total time from the fracture initiation in mini-frac, t (hr)
\( t_c \): closure time in mini-frac test, t (min)
\( t_D \): dimensionless time
\( t_e \): material balance time, t (D)
\( t_o \): initial production time, t (day)
\( t_p \): total pumping time from fracture initiation, t (hr)
\( T \): absolute temperature, T (K)
\( T_c \): critical temperature, T (°F)
\( T_f \): transmissibility for each phase, L\(^3\)t/m (md/cp)
\( V_b \): mechanical bulk volume, L\(^3\) (cm\(^3\), bbl)
\( V_d \): downstream reservoir volume, L\(^3\) (bbl)
\( V_g \): grain volume, L\(^3\) (cm\(^3\), bbl)
\( V_{gas} \): gas-filled volume, L\(^3\) (cm\(^3\), bbl)
\( V_i \): total injection volume in mini-frac test, L\(^3\) (bbl)
\( V_u \): upstream reservoir volume, \( L^3 \) (bbl)
\( V_m \): mean volume of water, \( L/m - \text{mol} \) (l/g-mol)
\( V_R \): pore volume component, \( L^3 \) (bbl)
\( w_{hf} \): hydraulic fracture width, \( L \) (ft)
\( x_f \): fracture half-length, \( L \) (ft)
\( y_f \): fracture half-length, \( L \) (ft)

**Greek**

\( \rho \): apparent grain density, \( m/L^3 \) (g/cm\(^3\),lb/bbl)
\( \lambda_o \): oil mobility, \( L^3t/m \) (md/cp)
\( \lambda_w \): water mobility, \( L^3t/m \) (md/cp)
\( \lambda_g \): gas mobility, \( L^3t/m \) (md/cp)
\( \Delta p_{s,hf} \): skin pressure drop in hydraulic fracture stimulated well, \( FL^{-2} \) (psi)
\( \Delta p_{s,unhw} \): skin pressure drop in un-stimulated horizontal well, \( FL^{-2} \) (psi)
\( \Delta p \): well flowing pressure change, \( FL^{-2} \) (psi)
\( \phi \): porosity, fraction
\( \phi_m \): matrix porosity, fraction
\( \phi_f \): fracture porosity, fraction
\( \theta \): contact angle, (°)
\( \mu_g \): gas viscosity, \( m/LT \) (cp)
\( \mu \): oil viscosity, \( m/LT \) (cp)
\( \sigma \): matrix shape factor for the cubic matrix blocks, \( 1/L^2 \) (1/ft\(^2\))
\( \sigma_{ow} \): interfacial tension between oil and water, \( FL^{-1} \) (dyne/cm)
\( \sigma_c \): collision diameter for the used gas type, \( L \) (nm)
\( \sigma_{go} \): interfacial tension between gas and oil, \( mt^{-2} \) (dyne/cm)
\( \Omega \): EOS coefficients
\( \omega \): storativity ratio of fracture to the total system
\( \gamma \): ratio of the sample pore volume to the downstream reservoir volume
\( \tau \): source term, \( t^{-1} \) (1/D)
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