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EVALUATION OF SWEEP EFFICIENCY OF A MATURE CO₂ FLOOD IN LITTLE CREEK FIELD, MISSISSIPPI

A thesis

Submitted to the Graduate Faculty of the Louisiana State University and Agricultural and Mechanical College in partial fulfillment of the requirements for the degree of Master of Science in Petroleum Engineering

in

The Craft and Hawkins Department of Petroleum Engineering

by Didem Senocak B.S., Middle East Technical University, Turkey, 2006 December, 2008

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ABSTRACT

CO₂ displacement is the most widely used EOR process, but poor sweep efficiency and large CO₂ utilization rates are limitations to the economic and technical success of CO₂ floods. Developing a methodology to maximize the sweep efficiency and minimize the CO₂ utilization rate would greatly improve the economics of these fields. This thesis evaluates the sweep efficiency of a successful, late-in-life, continuous injection CO₂ flood at the Little Creek Field, Mississippi. In this work, we evaluate several heterogeneity measures in terms of recovery efficiency and utilization rate. Core studies available from 41% of the wells in the field were used to compute various heterogeneity measures, and the resulting values were correlated with pattern-by-pattern recoveries and CO₂ utilization rates. Weak correlation trends were found for most of the measures in terms of R^2 values. However, there was still a trend confirming the idea that more heterogeneity corresponds to higher utilization rates and lower recoveries. Mapping of the well-by-well heterogeneity measures appear to show geological trends better than traditional maps of the basic parameters that make up the measures. These geological trends were then successfully used to adjust rock-types during reservoir modeling. Reservoir simulation was performed to understand the reservoir response to CO₂ flooding and develop alternatives for sweep improvement. Continuous CO₂ injection under certain alternate operations would help. The WAG process was effective in increasing the sweep efficiency of the reservoir for most of the cases studied by providing favorable mobility ratios and contacting more of the oil in the reservoir. The Gas-Assisted Gravity Drainage (GAGD) process was also evaluated. Solvent saturation profiles show that results are essentially consistent with the proposed GAGD theory.

However, oil recovery was less than the best WAG cases, which is not surprising due to the high connate water saturation (0.56), relatively low thickness and lack of dip to the reservoir. Moreover, an increase in recovery could be realized more in the future for both the WAG and GAGD processes because CO_2 contacted larger amounts of unswept oil in the reservoir compared to continuous CO_2 flooding.

1. INTRODUCTION

Reservoir engineering was originally concerned with the calculation of the amount of oil and natural gas that could economically be produced from a reservoir. In recent years, the role of reservoir engineering has become more important in providing the best ways to maximize the recovery of oil and natural gas since they are indispensable in supplying the daily energy needs of the world. Recently, the oil price reached a record maximum of US \$147 per barrel. This clearly indicates the importance of oil in the world economy today.

Enhanced oil recovery (EOR) operations, including gas, air or water injection into a reservoir, are performed to increase the recovery of oil after natural reservoir energy has displaced the primary oil to the production wells (Willhite, 1986). Waterflooding, also known as secondary recovery, is the most common fluid injection method which initially occurred accidentally in Pithole City, Pennsylvania in 1865 (Craig, 1971; Willhite, 1986). Waterflooding is the main recovery method providing high production rates in the U.S and Canada (Craig, 1971). Since the late 1980's, the recovery of remaining oil in the reservoir after primary and secondary recoveries has been improved by CO₂ flooding which is one of the most promising EOR techniques for light oil (Grigg and Schechter, 1997).

Taber, et al. (1997) estimated that CO_2 flooding could produce some incremental oil from nearly four out of five of the world's reservoirs. Today, U.S. oil production from CO_2 flooding is approximately 240,313 barrels per day according to an EOR survey in the Oil & Gas Journal (Koottungal, 2008). Table 1 shows values for technically recoverable oil resources from CO_2 miscible floods in the U.S according to another recent survey performed by Advanced Resources International (Kuuskraa and Ferguson, 2008).

		DATA BASE	NATIONAL		
Basin/Area	OOIP (Billion Barrels)	OOIP Favorable for CO ₂ - EOR (Billion Barrels)	Technically Recoverable (Billion Barrels)	OOIP (Billion Barrels)	Technically Recoverable (Billion Barrels)
1. Alaska	65.4	64.5	12.0	67.3	12.4
2. California	75.2	31.6	5.7	83.3	6.3
3. Gulf Coast (AL, FL, MS, LA)	26.4	20.2	4.2	44.4	7.0
4. Mid-Continent (OK, AR, KS, NE)	53.1	28	6.4	89.6	10.7
5. Illinois/Michigan	12.0	4.6	0.8	17.8	1.2
6. Permian (W TX, NM)	72.4	63.1	13.5	95.4	17.8
7. Rockies (CO, UT, WY)	23.7	18	2.9	33.6	4.2
8. Texas, East/Central	67.4	52.4	10.9	109.0	17.6
9. Williston (MT, ND, SD)	9.4	7.2	1.8	13.2	2.5
10. Louisiana Offshore	22.2	22.1	4.6	28.1	5.8
11. Appalachia (WV, OH, KY, PA)	10.6	7.4	1.2	14.0	1.6
Total	437.8	319.1	64	595.7	87.1

Table 1: Technically Recoverable Resources from Applying "State-of-the-Art" CO ₂ EOR
Data Base and National Totals (after Kuuskraa and Ferguson, 2008)

Although CO₂ flooding is the most successful and widely used EOR process, poor sweep efficiency and high CO₂ utilization rates, defined as the ratio of the amount of CO₂ injected to the produced oil, are obstacles preventing the financial and practical success of CO₂ flooding (Taber, et al., 1997). This thesis will attempt to address this problem to improve the oil recovery with detailed analysis of reservoir performance. Sweep efficiency can be defined as a measure of how the overall displacement affects the recoverable mobile hydrocarbons. It can be formulized as (Green and Willhite, 1998),

$$E = E_D \times E_V \tag{1}$$

where *E* is the overall recovery efficiency, E_D is the microscopic displacement efficiency and E_V is the volumetric sweep efficiency. E_D determines the effectiveness of the injected fluid that contacts the moving oil while E_V shows the effectiveness of the injected fluid to sweep out the reservoir areally and vertically (Green and Willhite, 1998). In favorable EOR processes, the value of *E* approaches 1.0 resulting in low residual oil saturations, S_{or} . Miscibility between the fluids, reducing the effect of interfacial tension (IFT) between the fluids, oil volume expansion and reducing oil viscosity can increase the microscopic displacement efficiency (Green and Willhite, 1998). Favorable mobility ratios between displaced and displacing fluids improve both areal and vertical sweep efficiency (Green and Willhite, 1998). On the other hand, viscous fingering and gravity segregation are the main reasons for poor sweep efficiency. Moreover, geologic factors such as reservoir heterogeneity, high permeability zones or fractures always influence the completion and success of an EOR process. An EOR project failure can be avoided by identifying these factors with a number of methods including core and log analysis, pressure transient analysis, seismic surveys, etc. (Green and Willhite, 1998).

1.1 Objectives

Increasing the number of economically cost efficient CO_2 flooding applications is becoming more viable these days. Maximizing the oil recovery factor and minimizing the utilization rate would greatly improve the economical benefits. The main motivation for this thesis is to understand sweep efficiency by the study of a successful, late-in-life, continuous injection CO₂ flood at the Little Creek Field, Mississippi. We would like to understand what happened during the flood, what made the flood successful, and what might have been done differently to increase recovery. One way to evaluate the sweep efficiency is through a detailed simulation study in order to develop methodologies to improve the oil recovery factor by ensuring that the injected CO₂ contacts more of the reservoir. The ultimate goal in previous simulation studies on the Little Creek Field was history matching reservoir performance of the CO_2 pilot flood in order to design the full field operation. The purpose of our simulation study is not necessarily just to obtain history match in the pilot area, but to provide insight into the sweep process and to study alternatives to what was actually done in order to identify strategies to improve recovery. For instance, there has been no published simulation study of the Water Alternating Gas (WAG) injection process for the Little Creek Field. It may be too late in the reservoir life to improve recovery for this field, but this study will document what difference a WAG process might have made at Little Creek and hence might make in similar reservoirs elsewhere. Likewise, gravity stable processes will also be examined.

The understanding obtained from this thesis may lead to the development of operating practices for improving oil recoveries and reducing CO_2 utilization in other active or planned CO_2 injection projects which have poor sweep efficiency.

1.2 Outline

This thesis evaluates the sweep efficiency of a mature CO_2 flood in Little Creek, Mississippi in order to understand what operationally might have done differently and to identify strategies to improve recovery. The thesis can be divided into two main parts. The first part presents the results from a study of the available cores from the field. Some background information on the reservoir properties and development of the Little Creek Field will be introduced in Chapter 2. Chapter 3 presents an evaluation of the cores available from 41% of the wells in the Little Creek Field. The Dykstra-Parson and Lorenz coefficients were calculated for each well and the results were assessed in terms of their correlation to pattern area recovery efficiency and utilization rate at various times over the life of the flood. Although weak correlation trends were found with oil recoveries and slightly better correlation in terms of R^2 values were found for utilization rates, there was still a trend confirming the idea that more heterogeneity corresponds to higher utilization rates and lower recoveries. A detailed statistical analysis was also performed showing that the correlations between reservoir performance and the heterogeneity measures were statistically significant enough to show this idea. Much more significantly, mapping of the heterogeneity measures well by well appear to show geological trends better than traditional maps of more basic parameters. When doing reservoir modeling and history matching, these geological trends provided a successful way to adjust different rock types and guide mapping of permeability and porosity.

The second part of the thesis deals with understanding sweep in various parts of the field and evaluating alternatives for the improvement of the recovery by using reservoir computer simulation. The first proposal for a tertiary recovery process in the Little Creek Field by Shell Oil Company was to use a line drive pattern with high pressure natural gas in a pilot location. With the help of computer mathematical models, both the line drive and inverted nine-spot patterns were studied. The results from the Shell work proposed that an inverted nine-spot pattern was more efficient than the line drive and additionally verified that CO₂ injection instead of natural gas increased the recovery efficiency (Hansen, 1977a; Todd, 1970).

A pilot CO_2 flood was developed and implemented in early 1974 and after completion of pilot operations, simulation studies were done by Morse (1979), Youngren and Charlson (1980) and Cottrell (1984). The purpose of these studies was to evaluate the pilot response to CO_2 injection and develop an understanding of the mechanisms that influenced flood response in order to design the full field flood.

In this study, multiple areas of the field were evaluated and the pilot area was chosen as the initial study due to the previous work done in this region. While little information was provided in the previous studies about the reservoir response in the pilot area to waterflooding, relatively more information was provided on the reservoir performance as a result of the CO_2 flooding. A slightly different model is introduced which was designed to allow the waterflood response to be modeled. Once the waterflood history match was obtained, the response to CO_2 flooding was evaluated without modification to the basic parameters of the model. The results of this work are presented in Chapter 4 and in Chapter 5, an evaluation of alternative methodologies to increase recovery is presented. Then, the same method developed in the pilot area was used to assess flood response for an active region of the field. The results of this work are presented in Chapter 6.

2. LITTLE CREEK FIELD RESERVOIR PERFORMANCE

In this chapter, reservoir development and basic reservoir data of the Little Creek Field will be presented. After primary and secondary recoveries, the field has been subject to CO_2 flooding. The development of the field from initial discovery to the present will be described. Detailed information about the producing formations in the field will also be described.

2.1 Reservoir Development

The Little Creek Field was discovered by Shell Oil Company in January 1958, and is located in Lincoln and Pike Counties in southwest Mississippi (Figure 1). The producing pay zone is the lower Tuscaloosa (Upper Cretaceous) Denkman sand. The current operator designates the producing zones as the Q and the Q₂ sandstones (Walsh, 2007).



Figure 1: Little Creek Field (from Denbury Resources Inc., 2007)

The Little Creek Field originally contained an estimated 101.9 million barrels of oil (Cronquist, 1968; Hansen, 1977b). The primary drive mechanisms were said to be fluid expansion and solution gas drive with limited aquifer influx based on the early production data (Hansen, 1977a; Werren, et al., 1990). The field began to produce oil from the Shell-Lemann No. 1 well with 588 BOPD and 260 MCFGPD from an open-hole interval from 10,770 to 10790 ft (Werren, et al., 1990). The field was rapidly developed by drilling on 40 acre spacing in the northern part of the field and field production was around 9100 BOPD from 56 wells at the end of 1958 (Cronquist, 1968). The discovery of the southern part of the field was in November, 1958. Through 1961, 190 wells had been completed with 155 producers. Werren, et al. (1990) state that through 1990 the total number of wells in the field was 208 with 162 being producing wells. There are a total of 233 wells in the field today (Pennell, 2007).

Primary recovery was approximately 25 million barrels of oil (MMBO) which was 25% of the original oil in place (OOIP). A peripheral line-drive waterflood operation was initiated in early 1962. Waterflooding was very successful with an additional 21.7 MMBO (22% of the OOIP) produced during secondary recovery (Cronquist, 1968; Hansen, 1977a; Smith, 1973). Production decline began in 1964 and waterflooding was stopped in early 1970 (Cronquist, 1968). However, one well (Well 2-4A) produced oil until late 1978 even after waterflooding had ended.

Shell Oil Company considered different methodologies to recover the large amount of remaining oil considering that an estimated 47% of the OOIP was produced by primary and secondary means. They developed two miscible project options using reservoir simulation studies. A natural gas miscible displacement process was initially proposed, but they did not

pursue this option due to the high amount of natural gas required (Hansen, 1977a). Shell decided to pursue CO_2 flooding instead. A CO_2 pilot was performed between February 1974 and February 1977 and more than 120,000 bbls of oil (an additional 0.12% of the OOIP) was produced (Hansen, 1977a). After a long shut-in period in the field due to the construction of the Jackson Dome CO_2 pipeline and the field CO_2 injection facilities, tertiary recovery was initiated in December, 1985 (Werren, et al., 1990). Since that time, CO_2 has been continuously injected into the field, and an additional 18 MMBO (18.4% of OOIP) has been recovered in the past 22 years. Figure 2 shows the historical production and injection data provided by the current operator of the field, Denbury Resources Inc. Table 2 shows a comparison of the Little Creek Field to other CO_2 miscible projects from the 2008 Worldwide EOR survey from the Oil and Gas Journal (Koottungal, 2008).

Little Creek Field was operated by Shell Oil Company until J.P. Oil Company purchased the field in June, 1996. Denbury Resources Inc has been the operator of the field since the company acquired the field in September, 1999 (Senocak, et al., 2008). Inverted nine-spot pattern flooding is used for CO₂ injection operations and production wells that have uneconomically high gas-oil ratios are converted to injection wells. The reservoir has been subjected to CO₂ flooding for more than 20 years and was considered to be a good example for evaluating the flood performance of a late-in-life reservoir. Total recovery from the field is approximately 65% (calculated by 101.9 MMBO of OOIP); thus the target for any further EOR operations is the remaining 35%. The most important thing influencing the project economics for tertiary recovery processes is the amount of remaining oil. Denbury would certainly like to increase or accelerate recovery in Little Creek Field, but they also have other fields where they



Figure 2: Field Historical Production and Injection Performance

have CO_2 operations (including several in Louisiana). Therefore, identifying strategies and modifications to current operations to improve recovery in a long-term flood should be beneficial not only for Denbury but also to other operators considering CO_2 floods.

Operator	Field	Oil Gravity (⁰ API)	Previous Prod	Start date	So, % Start	So, % End	Project Maturity	Total Prod b/d	Enh. Prod b/d
Pure Resources	Dollarhide (Devonian)	40	Primary, Waterflooding	5/85	35	22	Half finished	2,420	1,970
Exxon- Mobil	Means (San Andres)	29	Waterflooding	11/83	-	-	Half finished	10,000	8,700
Merit Energy	Northeast Purdy	38	Waterflooding	9/82	-	-	Half finished	1,800	1,800
Chevron	Rangely Weber Sand	35	Waterflooding	10/86	38	29	Just Started	15,300	11,600
Occidental	South Welch	34	Waterflooding	9/93	50	15	Half finished	1,180	865
Great Western Drilling	Twofreds	36	Waterflooding	1/74	50	-	Nearing Completion	170	170
Merit Energy	Wertz	35	Waterflooding	10/86	-	-	Nearing Completion	3912	2986
Denbury Resources	Little Creek	39	Waterflooding	1985	44	21	Nearing Completion	1650	1650
Denbury Resources	West Mallalieu	40	Primary	1986	44	21	Half finished	6200	6200

 Table 2: 2008 Worldwide EOR survey (Selected Fields, after Koottungal, 2008)

2.2 Reservoir Properties

Little Creek Field is producing 39° API gravity crude oil from the Q and Q₂ sandstones. The average pay zone is at a depth of approximately 10,750 ft (10,350 ft subsea). The average net thickness of the Lower Tuscaloosa Q and Q_2 sandstones is 40 ft. The maximum net thickness of the Q sandstone is 55 ft while it is 30 ft for the Q_2 sandstone (Smith, 1973; Werren, et al., 1990). Figures 3 and 4 show the net isopach maps of the Q and Q_2 sandstones, respectively (Pennell, 2006).

The representative type logs shown in Figure 5 illustrate typical SP and resistivity responses and show wells that include both the Q and Q_2 sandstones, wells where only the Q sandstone with an abandonment facies is present, and wells where none of the sandstones occur (Werren, et al., 1990). The Lower Tuscaloosa Q-Q₂ sandstone bodies exhibit "fining-upward" response on electric logs and are interpreted as point bars deposited in a fluvial meander belt on a deltaic plain (Werren, et al., 1990). The age of the reservoir rocks is late Cretaceous, Cenomanian and the lithology is fine to medium-grained sublitharenite (Werren, et al., 1990).

The Q sandstone is the most common reservoir rock and was penetrated by almost all of the wells in the field. The Q_2 sand is not present over large sections of the field (Smith, 1973; Werren, et al., 1990). The Q and Q_2 sandstones are distinct markers, but they appear to be contiguous. Based on pressure and production data, it was interpreted that the two sands are in communication (Cronquist, 1968; Werren, et al., 1990). In some wells, the Q_2 sandstone, which is the lower layer, disconnects from the Q sandstone because of a shale zone in between. It merges back with the Q sand in most other parts of the field (Cronquist, 1968). Smith (1973) suggested that there are no data available indicating major discontinuities within the reservoir. In addition, it was also suggested that the continuity of the reservoir was usually obvious based on reservoir performance (Werren, et al., 1990).



Figure 3: Little Creek Net Q Sand Isopach Map (Pennell, 2006)



Figure 4: Little Creek Net Q2 Sand Isopach Map (Pennell, 2006)



Figure 5: The objective sandstones in Little Creek Field (from Werren, et al., 1990)

The reservoir was initially filled with undersaturated oil and Cronquist (1968) indicated that there was a common water oil contact (WOC) in the field at 10,415 ft subsea. However, Werren, et al (1990) found that "free and 100%-water levels" were at 10,425 ft and 10,420 ft, respectively based on production data, capillary pressure curves and log data. Cronquist (1968) claimed that there was usually no clean oil below 10,390 ft subsea and defined this depth as the base of the transition zone. A value of 10,415 ft subsea was used as a WOC contact level in our simulation model which will be discussed in Chapter 4. Table 3 summarizes the basic reservoir and fluid properties for Little Creek (Hansen, 1977a; Morse, 1979; Youngren and Charlson, 1980).

Reservoir Conditions and Fluid Properties						
Initial Reservoir Pressure	4840 psia					
Bubble-point Pressure	2150 psia					
Initial Reservoir Temperature	248 °F					
Initial GOR	555 SCF/STB					
Oil Formation Volume factor, B_o at P_i	1.32 RB/STB					
Oil viscosity at P_i	0.4 cp					
Oil viscosity at P_b	0.3 cp					
Oil gravity	39°, API					
Gas gravity	0.925 (air = 1.0)					
Connate Water Saturation, Swc	0.56					
Residual Oil Saturation, Sor	0.21					
Minimum Miscibility Pressure	4500 psia					

Table 3: Reservoir Parameters (from Hansen, 1977a; Morse, 1979;Youngren and Charlson, 1980).

3. CORE STUDY

In this chapter, core studies obtained from about half of the wells in the Little Creek Field will be discussed. These core studies were used to calculate the most widely used heterogeneity measures in an attempt to evaluate whether these measures have reasonable correlation with geology, oil recovery or CO_2 utilization for each pattern in the field. The focus was on using the core data to direct reservoir characterization and modeling.

3.1 Core Analysis

Ho and Ehara (2007) identify core analysis as a method to measure petrophysical properties of a reservoir such as permeability and porosity. Core samples collected from wellbores during drilling are used to observe the characteristics of the reservoir rock in the laboratory.

In this thesis, core data from the Little Creek Field was reviewed. There were 96 cored wells (out of 233) in the field (Senocak, et al., 2008). In Figure 6, all the wells with gold circles, regardless of their sizes, indicate the cored wells. The differentiation between the Q and the Q_2 sand was carried out by reviewing the logs. A total of 10 wells were found which had core data from the Q_2 sand (Senocak, et al., 2008). In this study, data from the Q and the Q_2 sands were usually aggregated to perform calculations since they appeared to be contiguous (Werren, et al., 1990).

3.2 Permeability and Porosity Relationships

In this section, the porosity vs. permeability distribution in the field is presented. The



Figure 6: Core Location Map

porosity and permeability for each core plug from the 96 cored wells in Little Creek is plotted in Figure 7. Although it is obvious that there is a wide trend of increasing permeability with porosity, it can also be seen that there is a wide scatter of points around this trend which is



Figure 7: Permeability- Porosity Crossplot

because of "grain size, grain sorting and clay content variations that are properties of fluvial sandstone reservoirs" (Jensen, et al., 2000). Note that, porosities range from 5.5% to 38.6%. However, a constant porosity of 23.4% had previously been used for evaluating flood performance (Cronquist, 1968; Hansen, 1977; Youngren and Charlson, 1980; Senocak et al., 2008). Air permeabilities vary from less than 0.1 md up to 4440 md. Note that the permeability values are generally less than 1000 md except for one high permeability zone in the interval from 10,367 ft to 10,379 ft subsea in Little Creek Unit Well No 27-14 (also called the Solomon-Atkinson Unit No. 1) (Smith, 1973). Note also that there is a line of permeability values at 0.1

md that may indicate a measurement limit of the permeameter used. Permeability values at or lower than 0.1 md were included in the core study if the values were determined to be from the main part of the sand body (i.e. within the perforated interval or within the SP deflection indicating the Q & Q_2 zones).

The arithmetic mean of the porosity values and the geometric mean of the permeability values including all data points from each cored well are 24.3%, and 33.8 md, respectively. For more accurate results, these variables were also calculated using data from 45 wells which had more than 15 measured data points per well. However, the results did not change drastically with an arithmetic mean porosity value of 24.1% and a geometric mean permeability of 32 md. The geometric mean is defined as the Nth root of the multiplication of a set of N positive numbers. The average of data distributed log-normally can be approximated by calculating the geometric mean (Smith, 1973). Permeability is a good example of a random variable with an approximately log normal distribution, so the geometric mean of permeability would be more representative than the arithmetic mean for the average permeability of the reservoir (Smith, 1973).

Subsequently, porosity-thickness (ϕh) and permeability-thickness (kh) of the cored interval for each cored well were calculated. Using these core derived ϕh and kh values, maps of these parameters were generated throughout the field using a database and mapping software package called Dynamic Surveillance System (DSS). This tool uses a standard nearest neighbor mapping procedure whereby the calculated value at a point is the average of each of the point values within a radius of influence divided by the squared distance from the calculation point to each known value (McMurray, 2008). These maps are shown in Figure 8 where darker areas correspond to larger values. The range of kh values was from 1000 to over 5000 md-ft while ϕh
values varied from 0.877 to over 13.241, across the field (Senocak, et al., 2008). The variation in porosity affects pattern volumes and original oil in place estimations. Using the pattern average porosities rather than the field average porosity resulted in a 5% increase in estimated oil in place for the field.



Figure 8: Maps of *ph* (left) and *kh* (right) from wells in the core study

3.3 Little Creek Channels

An important factor in the application of a CO_2 flood such as Little Creek is an understanding of reservoir heterogeneities and the recognition of the main flow channels in the

reservoir in order to evaluate sweep efficiency. Figures 9 through 11 are ancient Little Creek Field channels as interpreted by Smith (1973) and Werren, et al. (1990). Smith (1973) using information from a Shell internal report stated that the Q and Q₂ sandstones were point-bar deposits characterized by a meandering river system as shown in Figure 11 (from Smith, 1973). Figure 11 indicates the feasible point-bar trend and the main channel. Based on Werren's explanation, Smith (1973) stated that the Q₂ sand in the south part of the field must have had lower river energy than the Q sand as well as lower energy than the other Q₂ sands seen in the reservoir.



Figure 9: Interpreted depositional model (from Werren, et al., 1990)



Figure 10: Q marker to Top Q sandstone isopach map (from Werren, et al., 1990)



Figure 11: Little Creek Ancient Channel (from Smith, 1973)

Raj et al. (2004) defines river meandering as "an inherent characteristic of drainages in an alluvial plain". The broad channel system of a river tends to deposit sediment depending on

"planform geometry" (Raj, et al., 2004). Kamal (2006) shows a map and side view (crosssection) of a channel. He pointed out that the flow with highest velocity tends to go from outer corner to outer corner as the channel meanders down slope. Figure 12 (from Kamal, 2006) shows this interpretation. The highest velocity flow in the river tends to produce a smooth bed in the main part of the channel; however, the high velocity flow cuts deeper along the outside of river bends and shallower along the inside of river bends.



Figure 12: Diagram of a river channel (from Kamal, 2006)

Based on this general geologic understanding, the arrows in Figure 11 are showing the fastest current direction. However, Kamal (2006) also concluded that the highest velocity current switching from one side to the other generates a "helical flow" facilitating sediment deposition towards the inside of the bend. The sediment deposition would be fine-grained in the shallower parts of the river because the flow velocity would be lower.

In 1990, Werren, et al. (1990) suggested that the depositional feature for the Little Creek Field could be interpreted as shown in Figure 9. This figure shows how the wide meandering streams deposited the Q point-bars. Lighter regions correspond to river sand prior to abandonment facies. Hamlin and Cameron (1987) also stated that fluvial point bars are the typical depositional environment in the Little Creek Field.

Werren, et al. (1990) introduced a different approach to interpreting the channel sand. They suggested that the thickness from the Q marker to the top of the Q sand could be used as a channel map and indicates where the deposition of "fine-grained siltstone and mudstone" occurred. This map is shown in Figure 10 (from Werren, et al., 1990). They state that this map can be viewed as the last position of the river channel.

3.4 Heterogeneity Measures

The main objective of the core study was to evaluate the variation of the reservoir properties that affect flow. Reservoir heterogeneity has been important in understanding reservoir performance for years (Lake and Jensen, 1986). Jensen, et al. (2000) defined heterogeneity as "variability that affects flow". Permeability variations are the most obvious sources of heterogeneity. But it is the spatial arrangement of these permeability variations which most affects flow behavior.

A number of heterogeneity measures have been proposed to reflect the heterogeneity of reservoirs (Lake and Jensen, 1991). Initially, these heterogeneity measures allowed petroleum engineers to develop depletion schedules which better accounted for reservoir heterogeneity. Many enhanced recovery resources used these measures to provide a relative value to examine or explain the influence of heterogeneity on recoveries. With the development of statistical methods and reservoir simulation, heterogeneity measures were often relegated to relative measures of

heterogeneity and were shown to be insufficient to account for short- and long-scale correlation structures that may be present in a formation.

There are a number of quantitative expressions for permeability variation and they are summarized in Craig (1971). One of the earliest studies introduced by Miller and Lents (1947) used the positional approach technique in which core data from each well in a reservoir was divided into intervals of equal sand thicknesses, and the permeabilities for each interval was calculated by averaging within each sand thickness interval. They verified the agreement of gas cycling performance of reservoirs with this technique. Dykstra and Parsons (1950) evaluated the effect of permeability variation on waterflood predictions by using core data. They presented a correlation between their value called "coefficient of permeability variation" and recovery values from waterflooding. Schmalz and Rahme (1950) also proposed a heterogeneity measure called the Lorenz coefficient and attempted to use this coefficient to characterize the permeability distribution in a sand zone. In later studies, the Lorenz technique was adjusted by adding porosity to the calculation (Lake and Jensen, 1991).

These two most commonly used measures of heterogeneity in the petroleum industry both range from zero to one where higher values (those between about 0.5 and 1) correspond to higher heterogeneity (Lake and Jensen, 1986). In other words, a value of zero is for a completely homogenous reservoir while a value of one is for an "infinitely" heterogeneous reservoir; however, V_{DP} and L_C are usually not the same (Jensen, et al., 2000).

The Dykstra-Parson coefficient based on permeability distribution is computed as (Dykstra and Parsons, 1950; Lake and Jensen, 1991)

$$V_{DP} = \frac{k_{50} - k_{84.1}}{k_{50}} \tag{2}$$

where " k_{50} is the median permeability and $k_{84.1}$ is the permeability one standard deviation above k_{50} on a log-normal probability plot". Dykstra and Parsons (1950) declared that k_{50} and $k_{84.1}$ should be read from the straight line or "best-fit line" drawn through the data sorted in decreasing value and plotted on log-normal probability paper. Note that the line would be parallel to the base line if the reservoir rock was totally homogenous resulting from identical permeability values for all samples. The slope of the permeability variation line increases as the heterogeneity increases. Figure 13 is an example plot of the permeability data from the Skelly Ralph McCullough Well in the Little Creek Field (LCFU # 36-7). For this well, V_{DP} is 0.48.

Different definitions of V_{DP} such as "permeability-porosity ratios" and "variable sample sizes" have also been presented (Jensen, et al., 2000; Lake and Jensen, 1991); however, these definitions were not included in this study.

The Lorenz coefficient introduced by Schmalz and Rahme (1950) is computed from a plot of cumulative flow capacity, F_j versus storage capacity, C_j . The flow capacity and the storage capacity are calculated as follows (Jensen, et al., 2000)

$$F_{j} = \frac{\sum_{j=1}^{J} k_{j} h_{j}}{\sum_{i=1}^{N} k_{i} h_{i}}$$
(3) $C_{j} = \frac{\sum_{j=1}^{J} \phi_{j} h_{j}}{\sum_{i=1}^{N} \phi_{i} h_{i}}$ (4)



Figure 13: Example for Dykstra-Parsons Plot of Skelly Ralph McCullough Well (LCFU36-7)

where N is the total number of data values and $1 \le J \le N$. The partial sums are calculated after the data is ranked in decreasing order of k/ϕ . The Lorenz curve is then created by plotting *F* versus *C* on a linear graph. The Lorenz coefficient is equal to "twice the area between the Lorenz curve and the diagonal" (Lake and Jensen, 1991). Note that the Lorenz curve would be the straight diagonal line if the medium was homogenous (i.e. if all samples had the same permeability values) (Lake and Jensen, 1991). Increasing levels of heterogeneity with higher Lorenz coefficients is associated with higher transmissivity (*kh*), but lower storativity (ϕh) (Jensen, et al., 2000). Figure 14 is an example Lorenz plot for the Skelly Ralph McCullough Well in the Little Creek Field (LCFU # 36-7). For this well, L_C is 0.33.



Figure 14: Example for Lorenz Plot of Skelly Ralph McCullough Well (LCFU 36-7)

Dykstra-Parson and Lorenz coefficients were calculated for each of the 96 cores in the Little Creek Field. This is in contrast to the more common way to present heterogeneity information which is on a field-wide basis due to the typically limited amount of core data collected. Figure 15 shows a plot of Dykstra-Parsons coefficient vs. Lorenz coefficient for the Little Creek data. This plot includes data from both the Q and Q₂ sands for each well that has more than 15 data points. Wells with fewer than 15 measured values were not included in the heterogeneity measures part of the study. The V_{DP} values range from 0.47 to 0.96 with a mean of 0.45 and a standard deviation of 0.133. The L_C values range from 0.22 to 0.75 with a mean of 0.445 and a standard deviation of 0.11 (Senocak, et al., 2008).



Figure 15: Dykstra Parsons Variability vs. Lorenz Coefficient Plot

An attempt was made to correlate pattern performance to these heterogeneity measures. For each of the wells in a flood pattern in the field, the heterogeneity measures were compared to oil recovery and gross CO₂ utilization (defined as the ratio of the cumulative CO₂ injected to the cumulative oil recovered). Figures 16 and 17 show graphs of incremental EOR versus the Dykstra-Parsons and Lorenz coefficients respectively at different values of the hydrocarbon pore volumes (HCPV) of CO₂ injected. As can be seen from these plots, there is an expected trend that oil recovery generally decreases with increasing values of the heterogeneity measures and tend to be lowest for the highest values; however, there is a large variation which results in weak R^2 values.



Figure 16: Dykstra-Parsons Coefficients vs. Incremental Oil Recovery Plot



Figure 17: Lorenz Coefficients vs. Incremental Oil Recovery Plot.

When gross CO₂ utilization is plotted against the Dykstra-Parsons and Lorenz coefficients (Figures 18 and 19 respectively), a slightly better correlation is observed. In this plot, the trendlines for the 50% HCPV CO₂ injected and 100% HCPV CO₂ injected values are nearly parallel to each other; however, the slope of the trendline for the 200% HCPV CO₂ injected data falls off. The reason for the change in slope may be due to a fewer number of data points (only a few patterns have reached the 200% HCPV CO₂ injected value) or due to gas cycling which may be occurring due to gravity or viscous effects more than heterogeneity effects. Note that the Dykstra-Parsons and Lorenz coefficients were not correlated in any sense to EOR recovery or gross utilization when using the last available data rather than a consistent HCPV. Also note that the best correlations were found when the average porosities for each pattern were used, rather than the constant field average porosity of 23.4%.



Figure 18: Dykstra-Parsons Coefficients vs. Gross CO₂ Utilization Plot



Figure 19: Lorenz Coefficients vs. Gross CO₂ Utilization Plot

Jensen, et al. (2000) define the coefficient of determination, R^2 , as that proportion of the variability in a data set explained by the model being used to fit the data. This proportion can be computed from

$$R^{2} = 1 - \frac{\sum_{i=1}^{N} (Y_{i} - Y_{i})^{2}}{\sum_{i=1}^{N} (Y_{i} - \overline{Y})^{2}}$$
(5)

where Y_i is the observed data, and Y_i is the predicted data for a fixed value of X_i , as shown in Figure 20 (from Jensen, et al., 2000). So, R^2 would be equal to 1 if the residual values were zero.



Figure 20: The least-squared procedure (from Jensen, et al., 2000)

 R^2 is also defined as the square of the "sample correlation coefficient", *r*, which stands for "the product moment correlation coefficient of Bravais and Pearson" (Sachs, 1984) and is estimated by

$$r = \frac{\sum_{i=1}^{N} (x_i - \bar{x})(y_i - \bar{y})}{\sqrt{\sum_{i=1}^{N} (x_i - \bar{x})^2 \sum_{i=1}^{N} (y_i - \bar{y})^2}} = \frac{\sum_{i=1}^{N} (x_i y_i) - \frac{1}{n} (\sum_{i=1}^{N} x_i)(\sum_{i=1}^{N} y_i)}{\sqrt{\left[\sum_{i=1}^{N} x_i^2 - \frac{1}{n} (\sum_{i=1}^{N} x_i)^2\right] \left[\sum_{i=1}^{N} y_i^2 - \frac{1}{n} (\sum_{i=1}^{N} y_i)^2\right]}}$$
(6)

where x with a mean of \bar{x} and y with a mean of \bar{y} are the two variables, and n is the number of data points (Sachs, 1984). The square of the correlation coefficient, corresponds to R^2 assuming that x and y are bivariate normally distributed, and the relationship between x and y is linear (Sachs, 1984).

The correlation coefficient determines the relationship between the real parameters and the fitted regression model (Chatfield, 1983; Jensen, et al., 2000; Sachs, 1984). However, it needs to be considered that the best fit line may not be the correct model for evaluating the data. A single point can skew the fit line, causing significantly high residuals (Jensen, et al., 2000). In this study, R^2 signifies how much the variation in oil recovery and gross CO₂ utilization changes with respect to reservoir heterogeneity. A lower R^2 value is still satisfactory by confirming the expected idea. The correlation between the heterogeneity measures and oil recovery and gross CO₂ utilization could also be statistically significant although the R^2 is small.

Alternatively, another statistical approach called the analysis of variance (ANOVA) can be evaluated. R.A. Fisher established this statistical technique to analyze experimental results relying on different factors (Sachs, 1984). Gelman (2006) defines ANOVA as "a set of models that can be fit to data, and also a set of methods for summarize an existing fitted model". Sachs (1984) mentions that ANOVA assumes normal distribution and estimates the mean of group scores. There are different types of ANOVA depending on the effects of one or more treatment variables. In this study, the one way ANOVA technique for a single independent variable was used (ANOVA: Single Factor). The aim of this analysis is to determine if there is significant effect of heterogeneity on oil recovery and gross CO₂ utilization. The general form is as follows;

$$EOR = f(Heterogeneity)$$
(7)

$$Gross CO_2 Utilization = f (Heterogeneity)$$
(8)

The one way analysis of variance can be defined as (Sachs, 1984)

$$SS_{total} = SS_{within} + SS_{between} \tag{9}$$

where SS_{within} is "the sum of squares of the deviations of the observed values from the corresponding sample (group) means" and $SS_{between}$ is "the sum of squares of the deviations of the sample (group) means from the overall mean" (Sachs, 1984).

"The mean sum of squares (MS)" approximates the variances as (Sachs, 1984)

$$MS_{between} = \frac{1}{k-1} \sum_{i} n_i (\bar{x}_i - \bar{x})^2$$
(10)

$$MS_{within} = \frac{1}{n-k} \sum_{i,j} (x_{ij} - \bar{x}_{i.})^2$$
(11)

where;

k : number of groups n : total sample size (k-1) : degrees of freedom $(1 \le i \le k)$ (n-k) : degrees of freedom $(1 \le j \le n_i)$ $\bar{x}_{i.}$: sample average \bar{x} : overall (grand) mean

A larger value of $\frac{MS_{between}}{MS_{within}} = \hat{F}$ than $F_{critical}$ (found from tabulated values of F for (k-1), (n-k)

and significance level α) indicates that the group means are significantly different (Sachs, 1984). The \hat{F} term is calculated from (Sachs, 1984);

$$\hat{F} = \frac{\frac{1}{k-1} \left[\sum_{i} \frac{x_{i.}^{2}}{n_{i}} - \frac{x_{i..}^{2}}{n} \right]}{\frac{1}{n-k} \left[\sum_{i,j} x_{i,j}^{2} - \sum_{i} \frac{x_{i..}^{2}}{n_{i}} \right]}$$
(12)

Table 4 shows a comparison between F and $F_{critical}$ for populations of heterogeneity measures against both oil recovery and gross CO₂ utilization (SCF/STB). Despite the fact that the data fits for the heterogeneity measures vs. EOR recovery and utilization have smaller R^2 values than we would like them to have, the fact that $\hat{F} >> F_{critical}$ for all of the correlations shows that the trends are statistically significant.

Heterogeneity measure	HCPV CO ₂ , %	%OOIP EOR			Gross CO ₂ Utilization		
		\hat{F}	Fcritical	Confidence Interval, %	\hat{F}	F _{critical}	Confidence Interval, %
V _{DP}	50	938	4.1	97.7	49	8.9	97.5
	100	569	4.2	91.4	34.8	9.2	94.3
	200	310	4.4	76.4	135	10.6	90.6
L _C	50	312	4.1	98.1	49.2	8.9	98.4
	100	192	4.2	95.5	34.9	9.2	95.1
	200	78	4.5	82	136	11	92.4

Table 4: Comparison of \hat{F} to $F_{critical}$ and Confidence Intervals for T-test

In addition, a standard t-test to evaluate whether the slope of the line was significantly different from 0 was conducted for each of the regression lines. Confidence intervals that the slopes were significantly different from 0 were 98.4%, 95.1% and 92.4% for the Lorenz coefficient slopes for the utilization data and 98.1%, 95.5% and 82% for the recovery slopes. For the Dykstra-Parsons coefficient-utilization data, the confidence intervals were 97.5%, 94.3% and 90.6% and were 97.7%, 91.4% and 76.4% for the recovery slopes.

One reason for conducting the study was to try to see the main channel of the reservoir. Up to this point, it was hard to see the interpreted channels quite as easily as was hoped. As previously shown, net sand maps and the interpretation of the depositional setting show a distinct fluvial channel. It was difficult to see any sense of the channel with existing porosity-thickness and/or permeability-thickness maps (see Figure 8). It could be that the choice of the particular grey-scale color scheme prevents seeing the channel. What would help the characterization effort would be a quantitative measure that could aid in the detection of the main channel.

Surprisingly, the consistency with the channel models was observed when Dykstra-Parsons and Lorenz coefficients were mapped. Figures 21 and 22 show a similar "nearest neighbor" mapping technique from the DSS system where the parameter being mapped is the core-derived Dykstra-Parsons coefficient and Lorenz coefficient respectively. Lighter areas correspond to lower heterogeneity and are mainly in the heart of the field, while darker regions correspond to more heterogeneous values which are positioned around the edges. The lighter regions, especially those inside the red lines, are interpreted to be showing the main body of the channel. Although this interpretation is subjective, it is consistent with geological interpretations. It is also consistent with an evaluation of the channel distribution based on representative SP curves in the field as shown in Figure 23 (from Smith, 1973). As can be seen, SP curves which show impermeable shale separate from permeable and porous sands are likely to be channel deposits and are toward the middle part of the reservoir. Point-bar deposits tend to be at the edges of the reservoir. This behavior is a general characteristic of the depositional environment (Smith, 1973; Werren, et al., 1990). Blocky SP and bell shaped SP curves are interpreted as channel deposition with uniform porosity and permeability. Point-bar deposition is characterized by "fining upward" SP response with corresponding "fining upward" permeability values where high permeability is found towards the bottom of the zone and lower permeability towards the top of the zone (Smith, 1973).



Figure 21: Map of Dykstra-Parsons Variability Map



Figure 22: Map of Lorenz Coefficient Map



Figure 23: Representative "Q-Q₂" SP curve

An attempt was made to better define the exact contour of the channel instead of creating it subjectively. Ordinary kriging of the Lorenz coefficient values was used to obtain contour lines. Figure 24 shows the Lorenz coefficient kriging map where dark blue corresponds to lower Lorenz coefficients. As can be seen, it is not easy to see the main channel body compared to Figure 22. However, it is obviously showing some exceptional regions in the main channel where the Lorenz coefficients are higher and also showing the location of the areas which have lower Lorenz coefficients. When the Figures 22 and 24 were combined and observed together, the contours of the Lorenz map inside the interpreted channel can be seen much easier. In this figure, the interpreted main channel generally follows the contour map, but cross some contours in certain places and then follows the contours again. The dashed black line on Figure 25 deviates from the interpreted (red) line in several places, but is generally showing consistency



Figure 24: Lorenz Coefficient Kriging Map

with the interpreted result. Note that Figure 22 is the map which was used in this project, but attempts were made during the latter stages of the project to better define a method for determining the channel.



Figure 25: The contour map of the Lorenz inside the Channel

The Lorenz coefficient map indicated the channels more clearly compared to the Dykstra-Parsons map (Senocak, et al., 2008). Jensen, et al. (2000) stated that because the Lorenz coefficient calculation does not depend on "best-fit procedures" and thus is prone to less error, it is the preferred heterogeneity measure over the Dykstra-Parsons coefficient since it provides more accuracy and incorporates porosity as well as permeability.

From a petroleum engineering standpoint, the variation in permeability can cause unfavorable results in miscible displacements, because the injected solvent tends to pass through the higher permeability paths (Smith, 1973). However, gravity segregation could mitigate these effects if there is decreased permeability near the top of the reservoir (Smith, 1973). The importance of variations in permeability was considered in this work instead of assuming that the reservoir properties were uniform. Since the heterogeneity measures do not consider the lateral continuity of the heterogeneity (they are a measure of the vertical heterogeneity), layer-by-layer estimates of permeability and porosity will be incorporated into the simulation model. The interpreted channel system using the Lorenz coefficient map offers a way to determine different rock types in the reservoir simulation model. This work will be presented in Chapter 4.

4. PILOT AREA RESERVOIR SIMULATION

Chapter 2 discussed the reservoir and production data relevant to this study of sweep efficiency. All reservoir parameters used in the simulation model and details on the construction of the simulation model based on the core study will be presented in this chapter. The simulator used will be introduced briefly. Simulation studies of the CO_2 pilot in Little Creek have been done in order to evaluate field performance and explore alternative operations that might have increased recovery. Results from these studies will be presented in the next two chapters. A similar set of studies in an active region of the field will be described in Chapter 6.

4.1 Numerical Simulator

The IMEX software from the Computer Modelling Group (CMG) with the pseudomiscible option is a finite-difference, black oil simulator that was used in this study (Computer Modelling Group, 2007). This is similar to the systems used in previous studies. The pseudomiscible, black oil fluid model is based on the method introduced by Todd and Longstaff (1972) and is used to simulate the miscible displacement performance by representing the reservoir with a coarse numerical grid (Computer Modelling Group, 2007). In order to evaluate the mixing capability of the miscible fluids within the grid blocks, a mixing parameter ω is introduced (Computer Modelling Group, 2007). The ω parameter ranges from zero to one where a value of one stands for complete mixing of CO₂ and oil while a value of zero is for the case of no dispersion (Computer Modelling Group, 2007). For miscible displacement studies, an ω value of 0.33 is recommended (Todd and Longstaff, 1972) and this value was used for all of the studies in this thesis. The model consists of four-components which are water as the wetting phase, and gas, solvent and oil as non-wetting "phases". In this simulation study, it is believed that the pseudo-miscible model is sufficient to represent the CO_2 displacement process since it is faster and more efficient compared to computationally complex compositional models. The purpose of this work is to evaluate sweep and investigate options to improve sweep. This is viewed as being dominated by displacement. Had this work focused on current operations at Little Creek, the compositional model would be required since the recovery mechanism currently is more likely to be dominated by vaporization of the remaining oil rather than displacement.

4.2 Creating the Model

The structure map and the net pay isopach maps of the Q and Q₂ sands were obtained from Denbury Resources Inc (Pennell, 2006), in order to incorporate the structure and thickness variation throughout the reservoir into the model. This is somewhat different than what was considered in previous simulation studies at Little Creek where structure and net pay were represented in a conceptual sense, but not explicitly (Morse, 1979; Youngren and Charlson, 1980). The maps were digitized by using the WINDIG 2.5 digitizing software (Lovy, 1996). While digitizing, three points were chosen as reference points to set the boundaries of the environment. As many points as possible were digitized to keep the shape of the reservoir as close as possible to the original maps. Figures 26 through 28 show these digitized maps. They were brought into the CMG Builder software to begin the process of building the model.

In the simulation model for the pilot area, the grid system has considerably more grid blocks than in previous studies. A $14 \times 12 \times 4$ block grid system had been used in the Shell studies



Figure 26: Digitized Structure Map



Figure 27: Digitized Q Isopach Map



Figure 28: Digitized Q₂ Isopach Map

(Cottrell, 1984; Morse, 1979) while a $10 \times 10 \times 10$ grid system had been used in a study by ARCO (Youngren and Charlson, 1980). In a later Shell study, Cottrell (1984) added several grid cells near the edges of the pilot area as a sensitivity to the pattern area pore volume. Our three dimensional grid system is $50 \times 50 \times 8$ with the Q₂ sand in the last layer of the pilot area of the 20,000 grid cells in our study. 5,607 blocks were "pinched out" (i.e. the grid cells had no thickness and were removed from the active simulation grid (Computer Modelling Group, 2007). The grid was created as a Cartesian grid system with regular 120 ft × 120 ft grid cells over a 40×46 cell area. The remaining grid cells were expanded in an attempt to include extra storativity and flux outside the main reservoir "window". A 2D view of the grid system with the top of the first layer as the color scheme can be seen in Figure 29. The edge of the field to the east and south was not very well defined, so the most likely reservoir volume for these portions of the reservoir were determined after several adjustments to the model.

4.3 Aquifer

A limited water drive mechanism was believed to exist based on the early production performance (Cronquist, 1968). An aquifer was attached to the easternmost side of the model in order to evaluate the nature of the water influx and its influence on the water production. A Fetkovitch aquifer model was selected to represent the water influx in the reservoir. Aquifer size and strength were used as history matching parameters because the precise extension and strength were not known. The dimensions and ability to flow were changed until a reasonable history match result was obtained for primary and secondary recovery. The model aquifer properties giving the best history match are given in Table 5.



Grid Top (ft) 1958-01-01 K layer: 1

Figure 29: Cartesian grid system used in the simulations for pilot area

Aquifer Properties					
Flux Direction	i				
Thickness	15 ft				
Porosity	0.2				
Permeability	160 md				
Radius	1500 ft				
R-ratio	60				
Modelling Method	Fetkovitch				

Table 5: Aquifer Dimensions and Strength

4.4 **Production and Injection Data**

Data provided by Denbury Resources Inc. had some missing production and injection data for the pilot area. Different Shell reports, information from the Mississippi Oil and Gas Board and well files were used to compile the production and injection history because no single source had all of the data required from initial production to the end of the pilot. In case of any discrepancies between the reports, data from the Shell reports were used since it was considered to be a more reliable source. Most of the production and injection data were obtained from Hansen's Shell report (Hansen, 1977a) by digitizing the data from figures showing the daily production and injection for each well because only the cumulative field data was tabulated in this report. Figure 30 shows an example of one of the discrepancies between the Shell reports and the data provided by Denbury.



Figure 30: Cumulative Water Production

4.5 Fluid Properties

The reservoir crude oil was a highly undersaturated black oil with a stock tank gravity of 39° API and an initial gas-oil ratio of 555 SCF/STB. The initial reservoir pressure and the bubble point pressure were 4840 psi and 2150 psi, respectively (Werren, et al., 1990). Initial reservoir temperature was 248 °F and minimum miscibility pressure provided by Denbury Resources Inc. was 4500 psi. Note that this miscibility pressure is lower than the 4800 psi used by Youngren and Charlson (1980) and is also on the low side of the CO₂-recombined fluid critical point of 4700 psi \pm 300 psi measured by Orr (1976). Reservoir conditions and reservoir properties of the field were also given in Table 3. The miscibility assumption between CO₂ and Little Creek crude oil was shown to be valid based on the study of Morse (1979). The following table from Morse (1979) gives the C1 through C6 mole fractions.

Component	Mole, %	Liquid Volume %	
Hydrogen-Sulfide	-	-	
Carbon Dioxide	0.43	0.15	
Nitrogen	0.85	0.34	
Methane	27.67	8.33	
Ethane	8.69	3.43	
Propane	5.41	3.01	
iso-Butane	1.22	0.80	
n-Butone	3.16	2.01	
iso-Pentane	1.91	1.41	
n-Pentane	1.81	1.33	
Hexanes	4.64	3.81	
Heptanes Plus	44.21	75.38	
Heptanes Plus:	Specific Gravity $60^{\circ}/60^{\circ} = 0.8472$ API @ 60 °F = 35.5 Molecular Weight = 222		

Table 6: Hydrocarbon Components

In the simulation model, PVT data were obtained from Fair's PVT data analysis (Fair, 1987). Fair analyzed 72 PVT data points including laboratory analysis of fluid samples collected from different wells between 1958 and 1966. These fluid samples were below the measured bubble point pressure. The quality of the data was questionable because of variations in the sampling conditions and laboratories used (Fair, 1987). After performing a regression analysis on the 72 PVT data points, Fair concluded that some data with bubble point values less than 1900 psia were not representative of the original reservoir fluid because the flowing BHP was as large or larger than the measured bubble point. He neglected these samples in his analysis.

CO₂ properties required for the solvent PVT table in the simulation model were obtained from the Chemistry WebBook of National Institute of Standards and Technology (Watters, 2005) at pressure increments of 200 psia from 100 to 5100 psi 248 °F. The volume and density information obtained from this reference were used to compute the solvent expansion, formation volume and compressibility factors at each pressure.

4.6 Development of the Model Based on Core Study

Much of the initial input data for the reservoir properties shown in Table 3 were obtained from the previous Shell studies. However, there are some fundamental differences compared to the previous simulation studies in terms of using the data. In this simulation model, the porosity and permeability values at the well locations from the core study described in Chapter 3 were used as will be described in the next section. The effects of previously illustrated heterogeneity measures on the model will also be discussed later in this chapter.

4.6.1 Porosity and Permeability

Instead of using constant values for porosity and permeability throughout the field as was done in the previous simulation studies (Morse, 1979; Youngren and Charlson, 1980), values from the core study at each well were used. Porosity and permeability maps layer by layer were created. These reservoir properties from the core study were first determined for each layer separately in the pilot area. Porosity and permeability values at the well locations were then imported using the CMG Builder software. Layer porosity and x-direction permeability values for each grid cell in the layer were generated using the Ordinary Kriging estimation method (Computer Modelling Group, 2007). Ordinary Kriging is a geostatistical technique to interpolate the input data based on weighted nearest neighbor averaging. Variograms and search areas are required for this method. The variogram depends on the data variance as well as the distance between the data points (Computer Modelling Group, 2007). Variogram parameters for each layer in the model are presented in Appendix A.

In general, the use of Ordinary Kriging when populating reservoir models provides data values that are "too smooth" (Jensen, et al., 2000) and so is likely not the best method to characterize permeability and porosity values. Because there is more variability in permeability as compared to porosity, it may be a reasonable method for porosity but underestimates permeability variations. The intent in this work was not to do uncertainty qualification for the Little Creek Field. Geostatistical simulation and multiple realizations would be required for that effort. Building the model with multiple layers and basing the permeability and porosity values on the available core data was felt to be a reasonable compromise between representing the reservoir heterogeneity and having a model that had more heterogeneity than previous studies yet

was efficient for evaluating reservoir displacement and sweep enhancement options. Kriging of the logarithm of the permeability values would be a better option, but was not done for this part of the study. East-west vs. north-south permeability contrast was taken to be 2 to 1 in the pilot region based on information in Hansen (1977a). Vertical permeability values were assigned by multiplying the x-direction permeability by 0.001 (making $\frac{T_z}{T_x} \approx 0.58$).

4.6.2 Relative Permeability and Capillary Pressure

As described in the core study section, the Little Creek Field was found to be moderately heterogeneous. An attempt was made to incorporate the heterogeneity of the formation into the simulation model. By doing so, the effects of heterogeneity in the reservoir formation were investigated (especially the Lorenz coefficient map). It was observed that there was only a slight correlation between breakthrough times and the Lorenz coefficient map. However, there was enough to give some idea about the possible rock types.

Figure 31 shows the Lorenz coefficient map and the interpreted channel in the pilot area. The early cumulative water production for individual wells in the pilot area is shown in Figure 32. It can be seen that Well 1-10 began producing water essentially upon initial completion which could indicate that the well was completed in a transition zone. It can also be observed that several of the other wells produced water after a short delay presumably due to aquifer support. Also, note that nearly all of the wells had drastic increases in water production which indicated the waterflood response from early 1963 to late 1964.

A comparison of the Lorenz coefficient map and breakthrough times suggests that water flow is easier in the regions where the Lorenz coefficients are smaller. The explanation behind this interpretation is based on the fact that water moves from the easternmost side (see Figure 33). For instance, Well 1-10 began to produce water immediately as mentioned before and was followed by Well 1-2 and Well 1-6. The water movement from Well 1-2 and Well 1-6 to Well 1-3 and Well 1-12 is faster than from Well 1-10 to Well 1-11.

Relative permeability relationships were the subject of much discussion in the previous simulation studies. The original relative permeability curves generated by Core Laboratories during field development were always subject to revisions. The simulation models developed by Morse (1979) and Fair (1987) had resulted in not producing enough water when the original relative permeability curves were used. In both reports, water relative permeability curves were altered. They were altered to allow the water to flow easier and reduced the oil flow a bit.



Figure 31: Map of the Lorenz Coefficient in the Pilot Area


Figure 32: Cumulative Water Production Values



Water Saturation 1963-01-01 K layer: 1

Figure 33: Water Saturation Profile before Waterflooding in the Pilot Area

In this simulation model, two rock-type zones were defined based on the analysis of the water production values and the map of the Lorenz coefficients in the pilot area indicating that some of the water production could be due to poor quality rock. Figure 34 indicates the two rock regions set in the simulator. The red region corresponds to a rock-type which was assumed to be a lower quality region (i.e. more heterogeneous) while the blue region corresponds to an assumed homogeneous region based on the Lorenz coefficient map. The more homogeneous rock region used the same oil and water relative permeability curves as in the study by Fair (1987). In the more heterogeneous rock region, the oil flow was lowered a bit and had much higher curvature. The water relative permeability values were generally lower in this region as well, but with similar curvature as in the work by Fair (1987). Figure 35 shows the relative permeability curves used in this work.

Cottrell (1984) stated that it was believed that the effect of the oil-water capillary pressure curves on overall performance in the pilot area was weak. In this work, capillary pressure curves in the blue region were deemed negligible based on the thought that this region was more homogeneous or of higher quality. Oil-water capillary pressures were considered to be essential in the more heterogeneous region (red region) as evidenced by the interpreted transition zone production in Well 1-10. This "poor" rock region was located out of the main reservoir channel viewing it as something like an overbank deposit or the edges of the point bars. The capillary pressure curve used in Fair (1987) and those used in this work are shown in Figure 36. The capillary pressure relationship in Fair (1987) was obtained by a review of the petrophysical properties of Little Creek by Shannon (1984). In that review, Shannon generated one average curve from the capillary pressure data available from 36 air-mercury measurements on core

plugs from Little Creek. It was noted that the relationship was realistic based on saturation profiles viewed in the field (Fair, 1987).



Rel Perm Set Num 1958-01-01 K layer: 4

Figure 34: Rock-type regions set in the simulator









4.7 History Matching Results

Primary, secondary and CO_2 flood responses were simulated and history matched in the pilot area. The reason behind simulating the full history was to provide an estimate of the fluid saturations before the CO_2 flood started and to provide an accurate representation of the CO_2 response with minimal adjustments of the model to account for the complex response to the CO_2 flood. Oil production rates were used as the operating constraints for the history match. In some instances, total fluid production is required as a primary constraint if oil saturation values fall too low. That did not occur and the model was able to produce the specified oil rates throughout the history. As a result, oil rates are not shown in the history match plots.

In early versions of the model, 4 layers were used instead of 8. These initial attempts to match the history in the pilot area under the oil constraint mode resulted in a failure of the model to produce enough water during CO_2 flooding. The first acceptable match of the cumulative water production history was obtained when two rock regions based on core analysis were applied into the model. Additionally, gravity segregation of CO_2 into the upper layers occurred quite rapidly causing high solvent rates. Based on these results, the model was switched to an 8-layer model and vertical permeability was decreased which provided improvement in both water and solvent production in accordance with historical performance.

Wells in the pilot area are shown in Figure 37. The pilot was ¹/₄ of an inverted nine-spot pattern. Fluid was kept inside of the test pattern by five water injection wells (Wells 1-2, 1-3, 1-4, 1-5 and 1-12). Dark colored boxes in the figure correspond to production wells, whereas light colored ones are the water injection wells.



Figure 37: Wells in the Pilot Area

Pilot operations began with the initiation of water injection into the planned CO_2 injector and into the five injectors at the end of August, 1973. The intent of this injection was to increase the reservoir pressure from 4440 psi to above the minimum miscibility pressure (Hansen, 1977a). After December 1975, Well 1-2 was shut in and was no longer used as a water injection well. Well 36-15 was converted to a water injection well to substitute for Well 1-2 (Hansen, 1977a). Well 1-10 was used as the CO_2 injector. Shale barriers on the east and south side of the pilot area along with good productive capabilities of the wells, their nearness to the central production facilities and compressors, and the idea of negligible gravity effects because of the low structural dip in this region were some of the reasons for the selection of this part of the field as the pilot area (Hansen, 1977a; Smith, 1973). Pilot area cumulative production and injection history including primary and secondary recovery can be seen in Figure 38. Additionally, Figure 39 shows the water injection performance for each well in the pilot area.



Figure 38: Cumulative Production and Injection in Pilot Area



Figure 39: Cumulative Water Injection for Each Well

The area-wide history match to the cumulative water production between the years of 1958 and 1978 is shown in Figure 40. The field history matched result is quite good. In order to verify the model, history matches for each individual well are also shown. Figures 41 and 42 show the cumulative water production results including primary and secondary recovery for each individual well, where the red circles represent the observed water production data, and the blue solid line is the simulated water production response. As can be seen, the actual water production data and the simulated ones for each individual well are in good agreement. Figure 41 show wells that were deemed to have "good" matches while Figure 42 shows wells that have slightly poorer matches. Additionally, cumulative gas production for the area is shown in Figure 43. Simulated gas production during primary and secondary recovery also matches the actual gas production data reasonably well.



Figure 40: Field Water Production



Figure 41: Individual Well History Matches to the Cumulative Water Production



Figure 42: Individual Well History Matches to the Cumulative Water Production



Figure 43: Pilot Area Cumulative Gas Production History Match

Water production rates for each well are shown in Figures 44 and 45. Although the water production rate matches for the individual wells are not quite as good as the cumulative ones, they are still quite good and are a better indicator of possible model mismatches compared to the cumulative graphs. For instance, the model started to produce water in several of the wells a little earlier than history. It is also possible that the earliest water production data may not be recorded. The simulated water rates for each well in Figures 44 and 45 also show that the model missed some peak points of the water production.

History matching of the CO₂ flooding period was more challenging than the waterflooding period. Since it is a "window model" and the pilot area was shut in starting from the end of waterflooding until the initiation of the CO₂ flooding, the primary difficulty encountered was accounting for the flux into and out of the model region. This difficulty was overcome by using fake water injector and fake producer wells. In the early years (during secondary recovery), these wells were controlled by bottom-hole pressure according to isobar maps from Cronquist (1968) shown in Figures 46 through 48. The boundary conditions in the system were set up using these contours. As can be seen, pressure decreases during waterflooding from the easternmost side of the field (where the pilot area is) towards the middle part of the field. After June,1964, the BHP constraints for the wells were adjusted based on the water production history and kept constant. Our estimation was that this was the most reasonable way to handle the flux into and out of the model. The locations of these "fake wells" are shown in Figure 29.



Figure 44: Individual Well History Matches to the Water Production Rate



Figure 45: Individual Well History Matches to the Water Production Rate



Figure 46: Isobars and position of flood front (July, 1962) (from Cronquist, 1968)



Figure 47: Isobars (April, 1963) (from Cronquist, 1968)



Figure 48: Isobars and position of flood front (June, 1964) (from Cronquist, 1968)

The final model provided a good history match of water production for both waterflooding (see Figures 41 through 45) and CO₂ flooding periods which are shown in Figures 49 through 52. The overall simulated water production compared to the actual values for individual wells (Wells 1-6, 1-7 and 1-11) during CO₂ flooding are shown in Figures 49 through 51. The observed and simulated production data are in very good agreement for the individual wells during the CO₂ flooding period. The quality of the model can also be judged from Figure 52, which shows a comparison between the simulated and historical CO₂ production data.

Water rates, bottom-hole pressure and water cut values of individual wells during CO_2 flooding are shown in Figures 53 through 58. Although there are some differences, simulated water rates match the historical water rates slightly better during the CO_2 flooding period compared to the waterflooding period.



Figure 49: Well 1-11 Cumulative Water Production History Match (CO₂ Flooding)



Figure 50: Well 1-16 Cumulative Water Production History Match (CO₂ Flooding)



Figure 51: Well 1-7 Cumulative Water Production History Match (CO₂ Flooding)



Figure 52: Pilot Area Cumulative CO₂ Production History Match (CO₂ Flooding)



Figure 53: Well 1-11 Water Rate History Match and Bottom-hole Pressure



Figure 54: Well 1-11 Water Cut History Match



Figure 55: Well 1-6 Water Rate History Match and Bottom-hole Pressure



Figure 56: Well 1-6 Water Cut History Match



Figure 57: Well 1-7 Water Rate History Match and Bottom-hole Pressure



Figure 58: Well 1-7 Water Cut History Match

Although there was no tabulated pressure information in any of the reports provided, there is some information about the reservoir pressure in Cronquist (1968) and Hansen (1977a) mentions that the reservoir pressure in the pilot area was around 4400 psig in 1973 before pilot operations were started. In Figure 59, it can be seen that simulated average reservoir pressure is close to that value in 1973. The influence of the water injection initiated in late 1973 before the CO_2 flood started, can also be seen in this graph.



Figure 59: Average Reservoir Pressure before and during CO₂ Flooding

Hansen (1977a) claimed that the pilot area pressure reached about 5500 psig as a result of the water injection based on static surface pressure data from shut-in Wells 1-6 and 1-11. He also mentioned that the reservoir pressure decreased to around 5000 psi at the end of January, 1974

(Hansen, 1977a). The simulated pressure values in Wells 1-6 and 1-11 were slightly above 5000 psi by the end of the injection period rather than the reported 5500 psi. The more significant effect of the water injection can be seen in bottom-hole pressures of the production wells (see Figures 53 through 57). As these figures demonstrate, simulated well bottom-hole production pressures were generally higher than the minimum miscibility pressure of 4500 psi.

Operational problems and unanticipated declines in bottom-hole pressure were encountered in Well 1-7 and Well 1-6 (Hansen, 1977a) that dropped these wells below minimum miscibility pressure. With the beginning of CO₂ operations, the bottom-hole pressure in Well 1-11 had significantly increased (6300 psig in June, 1974) (Hansen, 1977a). The measured maximum bottom-hole pressure in Well 1-11 was 6974 psig in late 1974 and the pilot area pressure decreased slowly until pressure from this well declined to 5000 psig in early 1975 (Hansen, 1977a). The historical observations in Well 1-11 can be seen in its simulated bottomhole pressure (Figure 53) but the actual simulated pressure values are consistently lower than those stated in Hansen (1977a). He mentioned that the bottom-hole pressure in Well 1-7 drew down from 4956 psig in late August 1974 to 3538 psig in October 1974. Hansen (1977a) reported that they replaced a 1-inch choke with a 14/64 inch choke to solve this problem. Again, the simulated pressure values are not as low as reported, but are consistent with the observations.

4.8 Keys to the History Match

The history match results presented relied primarily on two things. First, an adequate primary and secondary recovery match which was controlled by the initial saturation distribution

and aquifer support. The two rock regions, and corresponding capillary pressure and relative permeability curves provided the solution to the initial reservoir response.

Second, since this is a window model, the saturation distribution at the start of CO_2 operations is a key. This distribution was controlled by the placement of the fake wells since this area had good information regarding the pressure and saturation movement from the maps by Cronquist (1968).

5. EVALUATION OF ALTERNATIVE OPERATIONS FOR THE PILOT AREA

According to the history matching results in Chapter 4, the quality of the simulation model was verified. Simulations were repeated under different operating scenarios to evaluate how the reservoir performance might be affected in the pilot area. This chapter will discuss the evaluation of alternative operational strategies to improve sweep efficiency.

Green and Willhite, (1998) state that many factors such as geology, fluid distributions and pattern-geometry effects should be taken into account in the development of a miscible displacement operation. They also emphasized that the understanding of reservoir heterogeneity is important for the operations. In this part of the study, reservoir analysis was done before evaluating the effect of using different simulation models. First, oil recovery was observed by examining the remaining oil saturation profile of the model at the end of CO₂ operations. The 3D oil saturation profile at the end of pilot operations is shown in Figure 60. As can be seen, the well (1-10) located in the lowest part of the reservoir had been used for CO₂ injection. The elevation of the well locations can be seen in Figure 61. Note that the 1-10 well is in the heterogeneous part of the reservoir based on the channel description from the Lorenz coefficients map discussed previously (see Figure 34).

According to Figure 60, the south part of the model still has high oil saturation values and the oil sweep was mainly deployed towards Well 1-11, especially in the top layers. Rapid response to the CO_2 flood and consequent oil breakthrough in Well 1-11, as well as previous reservoir simulation studies, provided evidence of the east-west and north-south permeability



Figure 60: Oil Saturation in 3D view at the end of pilot operations



Figure 61: Structure Map of the Top of the Formation in the Pilot Area

contrast. In this aspect, our model behavior was similar to the previous reservoir performance evaluations. Moreover, Figure 62 shows the solvent saturation profile. In the top layers, the CO_2 continues beyond Well 1-11. The reason for this could be that the east-west vs. north-south permeability ratio is 2 to 1 but it could also be that Well 1-11 was not completed in these layers.

Based on these observations, five alternative cases were constructed to compare the sweep efficiency under different scenarios. In all cases, the originally used pattern geometry of ¹/₄ of an inverted nine-spot and the five containing water injection wells (Well 1-2, 1-3, 1-4, 1-5 and 1-12) were kept the same. The limitations and different scenarios for each case are defined in the following sections.

5.1 Case 1 – CO₂ Injection from Well 1-6

In this case, Well 1-6 was used as the CO₂ injector and Wells 1-10, 1-7 and 1-11 were used as production wells throughout the life of the pilot operations. As in the historical model, Well 1-6 was completed in layers 5-7. Three different simulation runs were performed. In the 1^{st} run, the CO₂ injection well was controlled by CO₂ injection rates that were the same as the original pilot values in well 1-10 (a total of 3,373 MMSCF). The production wells were controlled by a bottom-hole pressure constraint of 5000 psi (above minimum miscibility pressure). In the 2^{nd} run, the model was the same as in the 1^{st} run, but included several wells as water injectors that were located in the south part of the pattern and originally were perforated in shallower zones (Wells 1-14, 1-14A and 1-13). The purpose behind this operation was to try to sweep oil trapped in the south part of the pilot area to the producing wells. These new injection



Figure 62: Simulated Solvent Saturation in Each Layer with Pilot Well Configuration

wells were completed in layers 1-7. The model in the 3^{rd} run is same as that in the 2^{nd} run, but production wells 1-10 and 1-11 were completed in all available layers. Well 1-10 was completed only in layers 2-6 and Well 1-11 was completed in layers 5-8 in the previous model. Well 1-7 was originally completed in layers 1-7 and both 1-7 and 1-10 do not have a Q₂ layer. Figures 63 through 65 shows the results of these runs.

Figure 63 shows that the model in the 3^{rd} run is capable of recovering more oil. A comparison of water cut and solvent production rates for each run to the historical values are shown in Figures 64 and 65. In the 3^{rd} run, the cumulative oil production during the CO₂ flooding period is around 200,000 barrels of oil. Water cut values are less than was seen in the actual pilot. Although there is early CO₂ production in all three runs, solvent rates are generally at about the same level as in the actual plot.



Field Cumulative Oil Production

Figure 63: Field Cumulative Oil Production for Case 1







Field CO2 Production Rate

Figure 65: Field CO₂ Production Rate for Case 1

An additional attempt was made to be able to see the sweep in a better sense by using the solvent saturation profile for the best scenario. Note that Well 1-6 is structurally higher than the original injector. Using Well 1-6 as an injector is then both a more gravity stable process and an attempt to sweep oil towards the reservoir boundary rather than away from the boundary. The difference between the original operations with Well 1-10 and this case can be seen in Figure 66 especially in the top layers. The CO_2 did not move into the top layer as far. Moreover, Figure 66 shows that solvent tends to go towards the northwest (towards Well 1-7) which is more obvious especially in layers 4-7. Thus, the CO_2 does not sweep the same region as the original pilot. The recovery for this particular case is better than the original one. More of the solvent seems to be staying in the region of study for this case especially in the upper layers. In addition, there are fewer isolated areas with high solvent seems to be staying within the layer it enters better than in the original pilot.

5.2 Case 2 – CO₂ Injection from Well 1-7

In this case, Well 1-7 was used as the CO_2 injector and Wells 1-10, 1-6 and 1-11 were used as production wells. Well 1-7 was originally completed in the first through seventh layers. For this case, the well was completed only in the lower layers (layers 5-7). The same scenarios and limitations were applied as was done in the previous case. Figures 67 through 69 show the results of the well responses to the each different operation. Figure 67 shows that the model used in the 3rd run is producing significantly more oil than history. A comparison of water cut and solvent production rates for each run to the historical values are given in Figures 68 and 69. The



Figure 66: Solvent Saturation Profile for the best scenario in Case 1



Figure 67: Field Cumulative Oil Production for Case 2



Figure 68: Field Water Cut for Case 2



Figure 69: Field CO₂ Production Rate for Case 2

cumulative oil production in the 3^{rd} run is approximately 218,000 bbl during the tertiary recovery period. Water cut values and CO₂ production rates are generally at the same level as history, but there is again early CO₂ breakthrough.

Figure 70 shows the solvent saturation values in each layer for the best scenario. There is again success in preventing CO_2 deployment into the top layers. Based on Figure 70, most of the solvent moves oil toward Well 1-6. A much smaller amount moves toward Well 1-10, and the least toward Well 1-11. Very little CO_2 is lost outside the region of interest. Because there is a much smaller amount of solvent that has moved towards Well 1-11 and 1-10, it may be possible to continue the injection process by shutting in Well 1-6 if solvent rates are too high and continue to recover more oil.



Figure 70: Solvent Saturation Profile for the best scenario in Case 2

5.3 Case 3 – CO₂ Injection from Well 1-11

In this case, everything is the same as Case 1 and 2 except that CO_2 is injected into Well 1-11 which is completed in the fourth through eighth layers, and Wells 1-10, 1-6 and 1-7 are used as the production wells. The results for this case can be seen in Figures 71 through 73. The best response is again from the 3rd run, and 230,000 bbl of oil is produced during the CO_2 injection period. Water cut values in this run are lower than and CO_2 production rates are generally at about the same level as the historical values.



Figure 71: Field Cumulative Oil Production for Case 3







Field CO2 Production Rate

Figure 73: Field CO₂ Production Rate for Case 3

Figure 74 shows the solvent saturation profile for the best scenario. This time the solvent deployment to the top layers is again much less than the original pilot. A large amount of CO_2 is deployed throughout the region of interest and contacts most of the oil between Wells 1-6 and 1-10. Additional recovery may be possible as Well 1-7 has not had significant contact with solvent, but the areal extent of this region in each of the layers is smaller than in the previous case.

Cases 1 through 3 provide significantly higher oil recovery than historical values. Much of this additional recovery is by moving oil out of the southern area and by completing additional layers to allow more solvent to enter and sweep oil out of those layers. These both may be model artifacts; however, monitoring the remaining oil saturation profile provided the capability to examine the reservoir development and observe oil possibly trapped in parts in the reservoir. Operational changes based on these observations could then be implemented to improve the recovery.

A summary describing the different scenarios for Cases 1 to 3 can be seen in Table 7

5.4 Case 4 – WAG Technique

Undesirable mobility ratios due to the low viscosity of the displacing fluid compared to the displaced fluid cause poor sweep efficiency (Green and Willhite, 1998). In 1958, Caudle and Dyes developed the water-alternating-gas (WAG) process by suggesting the injection of water and gas alternately to alleviate this problem (Green and Willhite, 1998). WAG injection ratios generally range from 0.5 to 4 volumes of water per volume of solvent at reservoir conditions (Green and Willhite, 1998).



Figure 74: Solvent Saturation Profile for the best scenario in Case 3
Casas	EOR	Constraints		Injector	Run	Additional Operations
Cases	Туре	Injector	Producer		#	
Case 1	Continuous CO ₂ Injection	Historical CO ₂ injection rate	BHP = 5000 psi	Well 1-6	1	-
					2	1) Use wells 1-14, 1- 14A and 1-13 as water injectors
					3	 Use wells 1-14, 1- 14A and 1-13 as water injectors Perforate wells 1-10 and 1-11 in all layers
					1	-
Case 2	Continuous CO ₂ Injection	Historical CO ₂ injection rate	BHP = 5000 psi	Well 1-7	2	1) Use wells 1-14, 1- 14A and 1-13 as water injectors
					3	 Use wells 1-14, 1- 14A and 1-13 as water injectors Perforate wells 1- 10, 1-11 and 1-6 in all layers
				HP = 00 psi Well 1-11	1	-
Case 3	Continuous CO ₂ Injection	Historical CO ₂ injection rate	BHP = 5000 psi		2	1) Use wells 1-14, 1- 14A and 1-13 as water injectors
					3	 Use wells 1-14, 1- 14A and 1-13 as water injectors Perforate wells 1- 10 and 1-6 in all layers

Table /: Summary of the Cases	1-3
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In Case 4, an attempt was made to understand how the oil sweep might be affected if the pilot area was operated by a WAG technique. Five different simulation runs for each of the previous 3 cases were performed to investigate the impact of WAG ratio and WAG cycles. Both CO_2 and water were injected in the same well in cycles. In the first three runs, a WAG process was simulated consisting of one year CO_2 injection followed by one year of water injection performing at WAG ratios of 1:1, 1:2 and 4:1 respectively (HCPV of CO_2 injection was always kept the same as the original values, and the injected water amount was calculated based on the specified WAG ratio). In the last two runs, simulations of 3 months of CO_2 injection and 3 months of water injection were followed by one month of CO_2 injection and one month of water injection. A WAG ratio of 1:2 was used for these runs.

Figures 75 through 77 shows the cumulative oil, water cut and CO₂ production rates for the runs using Well 1-6 as an injector compared to the best recovery from Case 1 (Run 3). During the WAG process, the highest cumulative oil production was about 265,000 bbls of oil (when the WAG ratio is 1:2 with one month cycle). This is more than twice the amount of oil produced during the continuous CO₂ flood pilot and about 15% more than the simulated oil produced from the equivalent continuous injection model. Note that there is not much difference between the historical water cut and the one in this run (it is even slightly less). There is still earlier breakthrough in the solvent production, but the cumulative CO₂ production is about 1,730 MMSCF which is much less than the 2,740 MMSCF in the base run (3rd run of Case 1). Note that the total CO₂ production in the WAG simulation (1,400 MMSCF in March, 1977) is also smaller than the historical value (about 1,760 MMSCF in March, 1977 which is the last data obtained).



Figure 75: Field Cumulative Oil Production (Well 1-6 is injector)



Figure 76: Field Water Cut (Well 1-6 is injector)

Field CO2 Production Rate



Figure 77: Field CO₂ Production Rate (Well 1-6 is injector)

Figures 78 through 80 show the cumulative oil, water cut and CO_2 production rates for the runs using Well 1-7 as an injector compared to the best run for Case 2 (Run 3). The best cumulative oil production is approximately 310,000 bbl. The oil is recovered at a water cut relatively consistent with history. The solvent production is again earlier than historical data and the cumulative CO_2 production is about 2,560 MMSCF. This is smaller than the 3,060 MMSCF in the base run (3rd run of Case 2) but is higher than the historical value (about 1,760 MMSCF in March, 1977). In this case, a comparison of the cumulative solvent oil ratio during CO_2 flooding is important. It is 8 MSCF/bbl in March, 1977 while it was 14.7 MSCF/bbl for the same month in the historical data (see Figure 81).



Figure 78: Field Cumulative Oil Production (Well 1-7 is injector)



Figure 79: Field Water Cut (Well 1-7 is injector)

Field CO2 Production Rate



Figure 80: Field CO₂ Production Rate (Well 1-7 is injector)



Figure 81: Field Cumulative Solvent-Oil Ratio (Well 1-7 is injector)

A comparison of the cumulative oil, water cut and CO_2 production rate for the runs using Well 1-11 as an injector can be seen in Figures 82 through 84. In the best response to this operational process, the cumulative oil production is approximately 284,000 bbl. The oil is recovered at a relatively lower value of the water cut than seen in the historical data. There is still earlier breakthrough of the solvent, but the cumulative CO_2 production is at a value of about 1,900 MMSCF in the WAG runs rather than about 2,830 MMSCF in the base model run (3rd run of Case 3). The total CO_2 production for this model is slightly lower than the historical value (1,570 MMSCF vs. about 1,760 MMSCF in March, 1977).



Figure 82: Field Cumulative Oil Production (Well 1-11 is injector)



Figure 83: Field Water Cut (Well 1-11 is injector)



Field CO2 Production Rate

Figure 84: Field CO₂ Production Rate (Well 1-11 is injector)

The results of these scenarios for each different CO_2 injector indicate that one year of CO_2 injection and one year of water injection used in the first three runs produce much more oil than history. Different WAG ratios with this cycle did not change the oil recovery significantly, but did increase the water cut. More frequent cycles of WAG injection with a 1:2 WAG ratio increased the oil recovery more for each different injector. Figure 85 shows a comparison of the different CO_2 injectors in terms of cumulative oil production as a function of time. The best oil recovery is obtained when Well 1-7 is used as a CO_2 /water injector with a 1:2 WAG ratio in one month cycles. Thus, it can be concluded that a WAG process using the 1:2 ratio and with one month cycles injecting in Well 1-7 would yield the maximum incremental oil recovery in the pilot area.



Figure 85: Comparison between the best recoveries from all runs for each injector

Additionally, the WAG process was simulated using Well 1-10 as a WAG injector without any additional operations (Well 1-10 was the original CO_2 injector). The aim was to understand the difference between continuous CO_2 injection and the WAG process under original operations.

Figures 86 through 88 show the cumulative oil, water cut and CO_2 production rate for the runs using Well 1-10 as an injector. The best cumulative oil production is approximately 177,000 bbl during CO_2 flooding. In that run, the oil is recovered at a water cut relatively consistent with history. The solvent production is again earlier than historical data, but it is much lower than history from late 1975 to late 1976. Note that according to these results, the pilot area would recover 77,000 bbl more oil if it was operated using the WAG process rather than continuous CO_2 flooding.

A summary of the different scenarios for Case 4 is shown in Table 8.



Figure 86: Field Cumulative Oil Production (Well 1-10 is injector)



Figure 87: Field Water Cut (Well 1-10 is injector)



Field CO2 Production Rate

Figure 88: Field CO₂ Production Rate (Well 1-10 is injector)

The solvent saturation profile for the best scenario (when Well 1-7 was used as a CO_2 /water injector at a WAG ratio of 1:2 with one month WAG cycle) can be seen in Figure 89. The CO_2 in this case moves away from the injector in a nearly radial pattern when compared to Figure 70 showing the solvent saturation values for the continuous CO_2 displacement. This seems to show that the model stabilized the solvent front, which provides a more favorable mobility ratio to increase the sweep efficiency.

However, it needs to be stated that reservoir simulation tools are useful in the prediction of fluid movement, but not in the simulation of operational problems. Hansen (1977a) stated that there were operational problems when water and CO_2 were mixed in this reservoir. He mentined that all producers produced considerably large amount of sand during pilot operations. Well 1-7, which is located at the edge of the reservoir, had been "sand-fraced" during its water injection life and was the most problematical source in terms of sand production (Hansen, 1977a). This could be the reason why the water alternating gas process was never tried at Little Creek. Reservoir simulations cannot predict operational difficulties, but if there are no operational difficulties, then the simulation results show that the WAG process would certainly help. In this particular case, a 1:2 WAG ratio with one month cycle is the best choice.

Attempting to overcome unfavorable mobility ratios between the injected CO_2 and the oil displaced by the WAG technique yielded better EOR performance than continuous CO_2 injection in the simulated model. However, one of the other problems with the WAG process mentioned in several published materials is the reduction of the displacement efficiency at the pore scale especially in water-wet rocks (Green and Willhite, 1998). Unfavorable mobility ratios at the solvent and oil interface results in viscous fingering of solvent bypassing the oil. This would



Figure 89: Solvent Saturation Profile for the best scenario in a WAG technique (CO₂ Injection from Well 1-7)

0	Constraints		Additional	T • 4	Run	EOR
Cases	Injector	Producer	Operations	Injector	#	Туре
				Well 1-6	1	WAG 1:1
			 Use wells 1-14, 1-14A and 1-13 as water injectors Perforate wells 1-10 and 1-11 in all layers 			1 year cycle
Case 4					2	WAG 1:2
						1 year cycle
					3	WAG 4:1
						1 year cycle
					4	WAG 1:2
						3 month cycle
					5	WAG 1:2
						1 month cycle
				Well 1-7	1	WAG 1:1
			1) Use wells 1-14		1	1 year cycle
	Original HCPV of CO ₂ injected and water injection rate based on WAG ratios		1 - 14 and $1 - 13$		2	WAG 1:2
			as water			1 year cycle
			injectors		3	WAG 4:1
			2) Perforate wells			l year cycle
			1-10,1-11 and			WAG 1:2
		BHP = 5000 psi	1-6 in all layers		5	3 month cycle
						WAG 1:2
						I month cycle
			 Use wells 1-14, 1-14A and 1-13 as water injectors Perforate wells 1-10 and 1-6 in 	Well 1-11	1	WAG I:1
					2	
						WAG 1.2
					3	
						1 year cycle
					4	WAG 1.2
						3 month cycle
			all layers		5	WAG 1.2
						1 month cycle
				Well 1-10	1	WAG 1:1
						1 year cycle
					2	WAG 1:2
						1 year cycle
			-		3	WAG 4:1
						1 year cycle
					4	WAG 1:2
						1 month cycle

Table 8: Summary of the Case 4

occur when solvent velocities are higher than water velocities due to smaller water injection volumes. Alternatively, more oil might be trapped because of high water saturation at the solvent and oil interface. This would occur in the case where too much water injection occurs and water velocities are higher than solvent velocities (Green and Willhite, 1998). Thus, an optimum water and solvent injection ratio providing equal water and solvent velocities would be important in a WAG process.

Rao, et al. (2004) mentioned that the field performance of WAG floods have been disappointing (which might be due to the use of inappropriate WAG ratios) and have yielded only 5-10% increases in oil recoveries. Based on this fact, they showed a comparison of a conventional view of the WAG process and the interpreted flow pattern considering the natural gravity segregation schematically depicted in Figures 90 and 91 (Rao, et al., 2004). As an alternative method to the WAG process, the Gas-Assisted Gravity Drainage (GAGD) process was introduced by Rao, et al. (2004). An attempt at the application of the GAGD process in the pilot area will be provided in Case 5.



Figure 90: Conceptual CO₂-WAG process (from Rao, et al., 2004)



Figure 91: Probable breakdown of a WAG cycle (from Rao, et al., 2004)

5.5 Case 5 – GAGD Technique

In this case, the effect of an innovative flood design and well placement technology was investigated. The GAGD process attempts to take advantage of gravity effects by providing vertical segregation between the injected CO_2 and reservoir oil (Rao, et al., 2004). This process uses horizontal production wells near the water-oil contact and existing vertical CO_2 injection wells (Rao, et al., 2004). The purpose of converting the producing wells to horizontals was to see if this would enable CO_2 to contact larger amounts of unswept oil in the reservoir, taking advantage of the gravity override phenomena (Kuuskraa, 2008). Figure 92 shows a diagram of the GAGD process. As can be observed from the figure, natural gravity segregation provides the accumulation of a CO_2 zone at the top of the pay zone and also provides the draining of oil and water down to the horizontal producers in the GAGD application. According to the theory in Rao, et al. (2004), the volumetric sweep efficiency would be maximized by a CO_2 zone moving

down and to the sides, providing more sweep of the reservoir. Rao, et al. (2004) also state that the natural gravity segregation would assist delaying, or eliminating breakthrough to the production well. Additionally, they pointed out that the maximum efficiency could be obtained if the reservoir pressure could be kept above the minimum miscibility pressure. In a later study, Mahmoud and Rao (2007) concluded that miscible GAGD process could recover almost 100% microscopic sweep efficiency and more than 54% in the tertiary mode.

The models providing the best recovery (3^{rd} case) in the first three cases were used as a basis for this part of the study. In the first runs, the vertical production wells were converted to horizontal wells and the vertical CO₂ injection well (but completed only in layers 1 to 4) was kept based on the GAGD theory. Horizontal sections of the production wells were completed in the center of the sixth layer (in order to stay away from the water-oil contact). An additional attempt was made by converting the injection well to a horizontal well in the top zone to further take advantage of the CO₂ segregation process.



Figure 92: Concept of the GAGD process (from Rao, et al., 2004)

The well constraints used were the same as the ones used in other cases in order to be consistent. The constraints for the CO₂ injection well was the historical injection rate and the constraints for production wells were bottom-hole pressures of 5,000 psi. Based on a study by Shedid and Zekri (2002), horizontal well lengths longer than 1,000 ft would provide an increase in well productivity for horizontal wells under steady-state conditions. Several models were simulated to predict the reservoir reaction to changes in the lengths and orientation of the horizontal wells. Considering the distances between the wells (especially between Wells 1-7 and 1-10 when they were used as production wells), a 1,200 ft length of horizontal section was used for horizontal production wells in each model. Laterally completed horizontal wells along the structure yielded the best recoveries. However, for the last three runs 360 ft length horizontal sections provided more recovery. Figures 93 through 95 show the horizontal well configuration and lengths which provided the best results for each case.







Figure 94: Horizontal Well Configuration (when Well 1-7 used as an injector)



Figure 95: Horizontal Well Configuration (when Well 1-11 used as an injector)

The responses for each run for three different horizontal and vertical injectors are shown in Figure 96. In the best scenario, Well 1-7 was a horizontal injector in the top layer, and 213,350 barrels of oil during CO₂ flooding could be recovered. For vertical injectors, the highest oil production is about 193,100 bbl when Well 1-6 was used as the injector and Wells 1-7, 1-10 and 1-11 were used as horizontal production wells. Note that the water cut levels are relatively lower than history in this scenario. This confirms the idea that sweep will be enhanced in the reservoir without an increase in water production as suggested by Rao, et al. (2004). Also note that solvent rates are generally lower than historical values until early 1977 (except when Well 1-7 was used as both a vertical and a horizontal injector). However, the production forecasts for Case 5 were not as beneficial as was hoped. Although the GAGD process was developed as an effective alternative to WAG, the simulated WAG cases produced more oil (almost 310,000 barrels of oil when Well 1-7 was a WAG injector vs. the 213,350 for the GAGD case).



Figure 96: Field Cumulative Oil Production for Case 5



Figure 97: Field Water Cut for Case 5

Field CO2 Production Rate



Figure 98: Field CO₂ Production Rate

The solvent saturation profile is shown in Figure 99. Because the solvent injector was completed in the first layer, there is a high amount of CO_2 in the top layers, and relatively less in the lower layers. As can be seen, a fair amount of the solvent contacts the region of interest in the top layers and drains the fluid down to the horizontal producers. So, the model is obviously consistent with the GAGD theory.

Rao, et al. (2004) mention that gravity-stable gas injection would be best if applied in low connate water saturation, thick, highly dipping or reef type light oil reservoirs with moderate to high vertical permeability. However, Little Creek has a high connate water saturation (0.56) and might not dip enough to be able to take advantage of the natural gravity segregation. Note that the vertical permeability values used in the model were fairly low in order to provide the history

match. This might be another explanation for the lower oil recovery results. In addition, Little Creek might not dip enough to be able to take advantage of the natural gravity segregation. The gravity number for the pilot area was around 10⁻⁶ when average values for reservoir and fluid parameters were used. Thus, the lower recovery results are not a surprise. It is encouraging that if an optimal well configuration can be determined, then the GAGD and WAG results can be similar for fields like Little Creek that may be sensitive to water injection.

One additional study was done to be able to compare the WAG and GAGD processes and to show if there is correlation of solvent saturation profiles to core and well log data. A cross-sectional view of the solvent saturation for each layer between Well 1-7 and Well 1-6 as the producer is shown in Figure 100 for both the WAG configuration and for the GAGD configuration. The solvent migrates through the middle layers in the WAG figure with only a small pocket of high solvent saturation near Well 1-7 in the 5th layer. This shows that the solvent does not channel to the producer and the WAG process seems to be working as in the theoretical pictures (Figure 90). The GAGD configuration also appears to be working as expected. The solvent is staying primarily in the top layers and gradually migrates down to the producer. The solvent saturation values are larger in the GAGD configuration primarily due to the fact that the water saturation value is fixed and the solvent is replacing oil in the GAGD configuration whereas the saturation values are clouded by the increased water saturation in the WAG process.

Figure 101 shows the SP log response and the core porosity and permeability data for these wells. Wells 1-6 and 1-7 appear to be in the main part of the channel based on this figure. Their porosity values are fairly constant but the permeability values have some variation throughout the zone especially in Well 1-6.



Figure 99: Solvent Saturation Profile for the best scenario in a GAGD technique at (CO₂ Injection from Well 1-7)

Figure 102 shows a comparison of the solvent saturation profile between Wells 1-7 and 1-11 in both the WAG and GAGD configurations. In this case, the WAG displacement is showing a slight rounding of the front location and the front has not yet reached the producer (Well 1-11 is much farther from the injector than Well 1-6). In the GAGD configuration, there is less solvent in the upper layers for this orientation than was seen between Wells 1-7 and 1-6. Part of the explanation for this might be that Well 1-11 has an SP profile that looks more like the classic point bar profile (Figure 103). In addition, the permeability values are much higher in the lower zones than in the upper zones in Well 1-11. Similar behavior can be seen in the profile between Well 1-7 and Well 1-10 (Figure 104). Again, Well 1-10 is slightly closer to Well 1-7 so more solvent has gotten to Well 1-10 than was seen at Well 1-11. The SP log shape again shows something more like a point bar shape and there is again a high permeability zone towards the bottom. In addition, there is a high permeability zone at the top of this well that does not appear in any of the other wells (Figure 105).

Note that in all of the above cases there are pockets of low solvent saturation near the production well. This likely indicates that there is even more oil that could be recovered and the ultimate plateau for the cumulative production is a bit higher. In contrast, the pilot recovery had reached its peak prior to termination of the flood.



Figure 100: Cross-sectional Solvent Saturation Profile between Wells 1-7 (injector) and 1-6 for the a) WAG case and b) GAGD case



Figure 101: Core and log data for Wells 1-6 and 1-7



Figure 102: Cross-sectional Solvent Saturation Profile between Wells 1-7 (injector) and 1-11 for the a) WAG case and b) GAGD case



Figure 103: Core and log data for Well 1-11



Figure 104: Cross-sectional Solvent Saturation Profile between Wells 1-7 (injector) and 1-10 for the a) WAG case and b) GAGD case



Figure 105: Core and log data for Well 1-10

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A summary of the different scenarios for Case 5 is shown in Table 9.

Cases	EOR Type	Constraints		Run	Iniector	Additional Operations
		Injector	Producer	#	J	Ĩ
Case 5	Continuous CO ₂ Injection	Original HCPV of CO ₂ injected and water injection rate based on WAG ratios	BHP = 5000 psi	1	Well 1-7 vertical	 Use wells 1-14, 1-14A and 1-13 as water injectors Perforate wells 1-10, 1- 11 and 1-6 in all layers
				2	Well 1-11 vertical	 Same as Run 1 Perforate wells 1-10 and 1-6 in all layers
				3	Well 1-6 vertical	 Same as Run 1 Perforate wells 1-10 and 1-11 in all layers
				4	Well 1-7 horizontal	 Same as Run 1 Perforate wells 1-10, 1- 11 and 1-6 in all layers
				5	Well 1-11 horizontal	 Same as Run 1 Perforate wells 1-10 and 1-6 in all layers
				6	Well 1-6 horizontal	 Same as Run 1 Perforate wells 1-10 and 1-11 in all layers

Table 9: Summary of the Case 5

6. RESERVOIR SIMULATION STUDY OF PATTERN 10-9

After the successful work done in the previous simulation study, it was believed that the understanding gained from modeling the pilot area could be used as leverage for other parts of the reservoir. Pattern 10-9 was chosen because it is one of the active regions in the field and because there was injection survey information which could be used to compare simulation to actual results other than productivity.

6.1 Development of the Model

Between the initiation of the pilot study and the initiation of this work, Denbury Resources Inc. had updated the Q and the Q_2 sand isopach maps (see Figures 106 and 107). These maps just include the south part of the field where Denbury continues their operations. These maps were used to provide the current information to the model of the pattern. Figures 108 and 109 show the digitized maps.

Similar to what was used in the pilot area study, the model for this pattern consists of a three dimensional $50 \times 50 \times 8$ Cartesian grid system (base grid cell sizes were 120 ft×120 ft). The Q₂ sand was again located in the bottom layer. 17,046 of the 20,000 cells were active. A 45 × 45 areal section of the reservoir contains the main portion of the pattern and the remaining grid cells were enlarged using the same reasoning as in the pilot area model. Figure 110 shows the grid system used for Pattern 10-9.



Figure 106: Little Creek Updated Q Sand Isopach Map (Walsh, 2007)



Figure 107: Little Creek Updated Q2 Sand Isopach Map (Walsh, 2007)



Figure 108: Digitized Updated Q Isopach Map



Figure 109: Digitized Updated Q₂ Isopach Map



Grid Top (ft) 1958-01-01 K layer: 1

Figure 110: Cartesian grid system used in the simulations for Pattern 10-9

The location of the aquifer attached to the southernmost side of the model was adjusted based on the stated water-oil contact due to a lack of information about the aquifer. The same aquifer properties giving the best history match in the pilot area (see Table 5) were used but the flux direction was changed to be in the *j* direction instead of the *i* direction for this pattern. The production and injection data provided by Denbury were used for Pattern 10-9 because there were no other published studies related to this area. Fluid and CO_2 properties were kept the same as in the pilot area.

Development of the model for Pattern 10-9 was much easier than the pilot area because the experience of modeling based on the core study was already acquired. Porosity and permeability values available at each well were calculated layer by layer in order to create their maps as was done previously. However, unlike in the pilot area study, the logarithm of the permeability values was used to create the maps instead of using the actual values. The Ordinary Kriging estimation method was again used for this region (see Appendix A for variogram information). The idea of the two rock types set according to the Lorenz coefficient map was applied, and the same relative permeability and capillary pressure curves for the two rock types were used in this model. Figure 111 shows the Lorenz Coefficient map and the interpreted channel in the Pattern 10-9 area. Pattern 10-9 is mainly inside the channel.



Figure 111: Map of the Lorenz Coefficient in the Pattern 10-9 125

The rock type regions set in the simulator are shown in Figure 112. The red region represents the heterogeneous part of the field; whereas the blue region represents the homogeneous region. Detailed information about these rock types has been given in Chapter 4.



Figure 112: Rock-type regions set in the simulator

6.2 History Matching Results

The history matching in this pattern leads to specific recommendations on active field operations that can improve the sweep efficiency. So, it is important to get a model reasonably matching the historical data to evaluate new strategies.

As was done in the pilot area, oil production rates for the production wells, and CO_2 for the injectors were used as the operating constraints and the historical water production data was used as the match data. Due to the lack of pressure data in this area, the simulated results will be used to check whether producing bottom-hole pressures were above the minimum miscibility pressure.



Figure 113: Wells in the Pattern 10-9

Pattern 10-9 shown in Figure 113 is an inverted nine spot pattern that becomes more of a line-drive orientation over time. Production wells are marked by green solid circles while injectors are marked by red solid triangles. Well 10-9 was the initial CO_2 injector for this pattern. Wells 11-5 and 11-12 were converted to injector wells when they "gassed out". Pattern 10-9 cumulative oil production and CO_2 injection history for each well can be seen in Figures 114 and 115.



Figure 114: Oil Production for Each Well in Pattern 10-9



Figure 115: Solvent Injection in Pattern 10-9
There was no water injection in this particular region, but it is still obvious to see the effect of waterflooding done in the surrounding parts of the field on Pattern 10-9. Water injection well locations and flood fronts defined by the 10% water-cut line along with estimated reservoir pressure contours are shown in Figures 116 through 118 (from Cronquist, 1968). In the field, the fluid front was moving towards the region of interest according to these maps. In other words, the sweep of oil from the north half and from the south part of the field allowed oil to enter the Pattern 10-9 area during the waterflooding period. In addition, CO₂ flooding operations in adjacent patterns were being developed at the same time as Pattern 10-9. Unlike the pilot area, it was very hard to supply the fluid flow from adjacent regions. This issue was resolved by setting water and oil injectors and producers at select locations in the expanded portions of the grid system to provide the extra fluid inflow and outflow. These wells (labeled "Fake" in Figure 110) were controlled by bottom-hole pressure according to the isobar maps provided by Cronquist (1968) as was done in the pilot area study. Figures 119 through 121 show the simulated pressures for these years which agrees reasonably well with the maps provided by Cronquist (1968). As can be seen, pressure decreases from the north and south of the region towards the middle part of the field through June 1964. After that time, the bottom hole pressure constraint on these wells was adjusted according to water production history and noted operational changes in adjacent wells. Note that the wells did not have continuous injection or production. They were one or the other at different times depending on the operational history, and the isobar maps from Cronquist (1968). Again, the saturation distribution prior to CO_2 operations in the area is a key to obtaining reasonable match results.



Figure 116: Isobars and position of flood front (July, 1962) (from Cronquist, 1968)



Figure 117: Isobars (April, 1963) (from Cronquist, 1968)



Figure 118: Isobars and position of flood front (June, 1964) (from Cronquist, 1968)



Figure 119: Simulated Areal Pressure Map (July, 1962)



Figure 120: Simulated Areal Pressure Map (April, 1963)



Figure 121: Simulated Areal Pressure Map (June, 1964) 131

The area-wide history match to the cumulative water production from the productive history of Pattern 10-9 is shown in Figure 122. As can be seen, cumulative water production was matched quite successfully. The final history matching results of the cumulative water production for some wells in the pattern are also shown in Figures 123 and 124 where the red circles correspond to the observed water production data, and the blue solid line is the simulated water production response. History matching results were generally similar in quality to those in the pilot area. History match results for the rest of the wells can be seen in Appendix B.





Figure 123: Individual Well History Matches for the Cumulative Water Production for Wells 10-8 and 11-12



Figure 124: Individual Well History Matches for the Cumulative Water Production for Wells 10-7 and 10-16

6.3 Evaluation of Alternative Operations for Pattern 10-9

The history matching results for Pattern 10-9 shown in the previous section and in Appendix B provide the basis from which to test the model under different operating scenarios and investigate how the reservoir response in Pattern 10-9 would be affected by these changes.

The progress of this section followed the same reservoir analysis methods as was done in the pilot area alternative operations section. First, the areal oil saturation profile predicted at the end of the history match simulation was examined to see the swept and unswept portions of the pattern. The layer by layer oil saturation distribution is shown in Figure 125. The simulator was run using all available production and injection data through May 2006 (the time of initiation of this study).

Additionally, the CO_2 saturation distribution at the end of the history match was also observed. Figure 126 show this solvent profile. The CO_2 reaches a large portion of the formation in the 4th, 5th, 6th and 7th layers. However, the amount of solvent deployment in the top layers decreases gradually, possibly due to the relatively lower permeability values in these layers. So, geological properties of the reservoir seem to help control the gravity effects in this part of the field more than was seen in the pilot area.

Note that CO_2 injection profile logs were run in the CO_2 injection well (Well 10-9) over the perforated interval in November, 2006. Injection profile logs determined that the upper 35 ft and the lower 5 ft were taking 28% of the injected CO_2 , and that a 10 ft section (20% of the perforated interval) in between was taking the remaining 72% of the solvent. This indicates that the injected CO_2 may be by-passing much of the oil saturated part of the upper zones. Solvent



Figure 125: Oil Saturation in 2D View for Each Layer of Pattern 10-9



Figure 126: Solvent Saturation in 2D View for Each Layer of Pattern 10-9

flux magnitude at reservoir conditions is the output parameter from the simulator that provides values similar to compare to the log response. This parameter is plotted in Figure 127 and shows that the majority of the solvent goes into layers 4-7 (the lower 57% of the reservoir). Based on the last data values in this figure, 73% of the solvent flux flows into the lowest 57% of the reservoir. This is somewhat different from the log result since there is no high injectivity zone above a low injectivity zone at the bottom of the formation. It is likely that there is a higher permeability zone that does not appear in the model since there is no core data for Well 10-9. However, the results are consistent in that the lower parts of the reservoir appear to be taking most of the CO₂. Consequently, there is probably still remaining oil especially in the upper layers as shown in Figure 125. Note that the CO₂ injection wells are located in the structurally higher parts of the pattern (see Figure 110) and that all the wells are inside the interpreted main channel (see Figure 112). Because of this, the original injection operations may be providing good sweep. However, the original well configuration for the pattern, or the miscible displacement process used might cause poor sweep efficiency.

Based on these observations and the knowledge gained during alternative operations part of the pilot area study (Chapter 5), different cases with different scenarios were developed in order to evaluate options for improving the sweep efficiency. Two different miscible CO_2 -water displacement processes using three different pattern geometries were used to evaluate the increase in oil recovery from Pattern 10-9: (1) WAG flood using the original nine-spot pattern, (2) continuous CO_2 injection and WAG using a five-spot well pattern, (3) continuous CO_2 injection and WAG using a line drive pattern. Three groups of well configurations were used: (a) vertical injection (V.I.) and vertical production (V.P.) wells, (b) vertical injection (V.I.) and horizontal production (H.P.) wells, and (c) horizontal injection (H.I.) and horizontal production (H.P) wells. Horizontal production wells were completed in the sixth layer, whereas horizontal injection wells were perforated in the first layer as was done in the pilot area study. Unlike in the pilot area study, during CO_2 flooding, the bottom-hole pressures that provided the best history match for each production well were used as the operating constraints in all cases for this study. In this way, oil recovery comparisons under current operations versus the different scenarios would be consistent. The different scenarios and other parameters for each case will be defined next.



Well 10-9 Flux Solvent Magnitude

Figure 127: Flux Solvent Magnitude for Well 10-9

6.3.1 Case 1 – WAG in a 1:2 Ratio with One-Month Cycles

Water-alternating CO_2 injection at a 1:2 WAG ratio using one-month cycles was the most successful technique in the pilot area. Thus, the effects of a WAG process on oil displacement were investigated in Pattern 10-9.

In this case, the original CO₂ injection wells (10-9, 11-5 and 11-12) were used as CO₂ and water injectors, alternately. Both CO₂ and water were injected in the same well in one-month WAG cycles in this case. Five different WAG models were simulated using the existing pattern geometry becoming more of a line-drive orientation over time. This is different from what would be done using the operating practices of the current operator. Current practice is to convert producers to injectors once the wells have reached an uneconomic gas-oil ratio. The aim for this part of the study was to show the differences between a WAG process and continuous CO₂ flooding using the same injectors as were used in the history. In the first three runs, the effects of three different well configurations were examined. The HCPV of CO₂ injected was kept the same as in the history; the injected water amount was calculated based on a WAG ratio of 1:2. Additionally, two more runs were performed by injecting only half the amount of CO₂ and water at WAG ratios of 1:2 and 1:1. The reason for doing this was to understand if it was possible to improve the economics by reducing the volume of CO₂ that needs to be injected into the reservoir. Only vertical injectors and producers were used in these two runs.

The results are shown in Figures 128 through 130. The highest recovery was obtained by vertical injection and production wells, followed by the horizontal production and injection configuration. The least amount of oil recovery was obtained by the horizontal production and vertical injection well case. Similar to the pilot area, this process is better than continuous

injection for this portion of the field. In the best scenario, the oil production increased nearly twice as much as in the historical continuous injection flood. The WAG process at 1:2 ratio yielded a final recovery of 6.7% OOIP for the VI-VP well configuration (5.1% OOIP had been recovered by primary and secondary recovery). Note that the water cut level is almost the same as in the historical result.

Figure 130 shows the solvent production rate. The model that provides the best history match is considered as the base model, and is compared to each of the alternative models because the history of solvent production data was not available. Note that the solvent production rate in the best scenario is generally lower than in the base model during early time. However, there are higher solvent rates in the last years of the simulation.

The model with the H.I and H.P. configuration produces oil at relatively lower solvent rates in the early years among the first three options. The oil production is slowly, but linearly increasing in these particular years. Because the oil production is relatively lower than the historical values in the early years, this model will not be as economical during these years. However, this option recovers more oil than all cases except the VP-VI 1:2 WAG. Note however that even for the lowest performing cases, the technique provides increased recovery over the historical continuous flood. Even for the cases where the amount of injected CO_2 was decreased by $\frac{1}{2}$, the reservoir response was nearly the same as in the history. The WAG ratio did not make a significant difference, but a WAG ratio of 1:1 resulted in an increase in water cut. Additionally, it can be seen that the solvent production rate was considerably lower.



Figure 128: Field Cumulative Oil Production for Case 1



Figure 129: Field Water Cut for Case 1





Figure 130: Field CO₂ Production Rate for Case 1

6.3.2 Case 2 – Five Spot

As mentioned before, a large amount of CO_2 does not reach the top layers based on the injection profile logs taken from Well 10-9 and the simulation results. This is probably because of lower permeability values in the top layers. Figure 131 shows the permeability distribution in each layer. Dark blue regions correspond to lower permeability and appear primarily around the injection and production wells in the upper 4 layers. Note that layers five through eight have relatively higher permeability zones around the wells.

 CO_2 injection from wells 10-9, 11-12 and 11-5 into the top layers may not be as effective due to these low permeability zones. In order to increase the sweep efficiency and provide that the injected CO_2 contacts more of the reservoir, having more CO_2 injection wells was thought to be an option to yield higher recovery. So, a five-spot pattern was considered for this part of the field.

In this case, the CO_2 miscible displacement process was performed under three different scenarios developed by using the same group of well configurations as in Case 1. Additionally, the effect of a WAG process using a five-spot vertical well pattern was also investigated.

Figure 132 shows the 2D five-spot pattern geometry of injection and production wells used for this case. Green solid circles correspond to production wells, whereas red solid triangles correspond to injectors. Unlike the original wells in the pattern, Wells 10-8, 10-10, 10-16, 15-2 and 14-4 were continuously used as injectors and 11-5, 10-9 were continuously used as production wells. In all scenarios, the total volume of CO₂ injection from history was equally distributed between the six injectors. In addition, the injection wells begin injecting CO_2 at the same time (September, 2000). The results for the different scenarios are shown in Figures 133 through 135. As can be seen, converting Pattern 10-9 from an inverted nine-spot to a five-spot well pattern increased the oil recovery for the continuous injection case. As expected, the WAG displacement process yielded the best incremental oil recovery, but also had the highest water cut level. The ultimate recovery would be increased from 6% to 6.5% of OOIP for the area, which is slightly lower than the 6.7% in Case 1. Similar to Case 1, the results for this case also support the theory that more recovery would be obtained using horizontal production and injection wells. Note that the solvent production rate is increasing continuously for all scenarios and is higher than in the base model in the last years, but that the WAG with H.P. and H.I. well configuration yielded relatively lower solvent production rates.



Figure 131: Permeability Distribution for each layer in Pattern 10-9



Figure 132: Five spot pattern geometry in Pattern 10-9



Field Cumulative Oil Production

Figure 133: Field Cumulative Oil Production for Case 2



Figure 134: Field Water Cut for Case 2



Field CO2 Production Solvent Rate

Figure 135: Field CO₂ Production Rate for Case 2

6.3.3 Case 3 – Line Drive

For this case, a miscible CO_2 -water displacement process using a direct line drive pattern was simulated. The design approach was similar to that used in Case 2. The same scenarios, continuous CO_2 injection using V.P.-V.I., H.P.-V.I, and H.P.-H.I. configurations and a WAG process at a 1:2 ratio, were applied using a line drive pattern.

Figure 136 shows the direct line-drive pattern geometry of injection and production wells used in the simulations. Unlike the original wells in the pattern, Wells 10-10, 15-2, 15-1 and 14-4 were used as injectors and Well 11-5 was continuously used as a production well. As was done in Case 2, the total amount of CO_2 injected from history was equally distributed between the six injectors and the injection wells began injecting CO_2 at the same time (September, 2000).



Figure 136: Direct Line Drive in Pattern 10-9

Figures 137 through 139 show the results of four different operating scenarios using the line drive pattern. For the development of a miscible displacement operation, this pattern geometry would not be more effective at oil recovery than the existing pattern geometry. The total oil production using vertical production and injection wells is about the same as in the history. The best oil production in this case was obtained from using a WAG flood and is the only case where significantly better recovery was seen. The total recovery under the WAG process is close to the one produced in Case 2, but the water cut level is much lower than in that case. However, higher oil recovery in the future with horizontal production and injection wells was not seen for this case. Note that the solvent production rate is not as high as in Case 2, but is higher than the base model during the last years of CO_2 flooding.



Figure 137: Field Cumulative Oil Production for Case 3







Field CO2 Production Solvent Rate

Figure 139: Field CO₂ Production Rate for Case 3

6.4 Summary of Alternative Operations for Pattern 10-9

In this chapter, a history matched model was used to evaluate the possible performance of the Pattern 10-9 area under three configurations: the original nine-spot pattern, a five-spot pattern and a line-drive well pattern. Each case had multiple runs using different well configurations under both continuous CO₂ injection and various WAG processes. For the Pattern 10-9 area, the WAG technique using V.I. and V. P. well configurations provided the highest recoveries similar to the pilot area. Note that the highest oil recovery was obtained when using the existing pattern geometry (6.7% OOIP). When the pattern was changed to a 5-spot pattern, the ultimate recovery decreased to 6.5% OOIP, but still was higher than historical values (6% OOIP). As mentioned in Chapter 5, the GAGD process has been developed as an alternative method to the WAG process. The process of using horizontal production wells near the bottom of the reservoir and horizontal injectors at the top (instead of vertical ones) can provide good recovery, but success depends on the pattern chosen. The results were positive using the existing pattern geometry and the five-spot but were negative for the direct line drive pattern.

The solvent saturation profile for the best scenario for the WAG technique (using V.P and V.I wells with the existing pattern geometry) is shown in Figure 140. Comparing this figure to Figure 126, it can be seen that same amount of CO_2 contacts more oil by using the WAG technique than continuous CO_2 flooding (especially noticeable in layers 2-4). The CO_2 tends to go more in a northeast direction out of the pattern in the continuous CO_2 flooding model, but it is mainly confined inside the pattern in the WAG technique. By comparison, Figure 141 shows the solvent saturation profile for the GAGD process by using H.P. and H.I. with the inverted 9-spot pattern geometry. Similar to the pilot area, a large amount of the solvent contacts the pattern in

the top layers and drains the fluid down to the horizontal producers which is consistent with the GAGD theory. The calculated gravity number for Pattern 10-9 was much lower than in the pilot area (about 4×10^{-7}). This might again be the reason of the lower oil recovery in the simulated GAGD technique.

A summary of the different scenarios for all cases is shown in Table 10.



Figure 140: Solvent Saturation Profile for the best scenario (WAG technique at a WAG ratio of 1:2 with one month WAG cycle using V.P and V.I wells in the existing pattern geometry)



Figure 141: Solvent Saturation Profile for the GAGD technique using H.P and H.I wells in the existing pattern geometry

	EOR	Constrai	nts	Pattern	Run	Well
Cases	Туре	Injector	Producer	Geometry	#	Configuration
		Original HCPV of CO ₂ injected			1	V.P. and V.I.
Case 1	WAG 1:2 ratio with one-month	and water injection rate based on WAG ratios	Simulated BHP that		2 3	H.P. and V.I. H.P. and H.I.
	cycles	$\frac{1}{2}$ of the Original HCPV of CO ₂ injected and water	provided the history matched	Original	4	V.P. and V.I.
	WAG 1:1 ratio with one-month cycles	injection rate based on WAG ratios			5	V.P. and V.I.
Case 2	Continuous CO ₂ Injection		Simulated		1	V.P. and V.I.
		CO_2 injected			2	H.P. and V.I.
		2 5	BHP that		3	H.P. and H.I.
	WAG 1:2 ratio with one-month cycles	Original HCPV of CO ₂ injected and water injection rate based on WAG ratios	provided the history matched	5-spot	4	V.P. and V.I.
	Continuous				1	V.P. and V.I.
Case 3	CO_2	Original HCPV of CO ₂ injected	Simulated		2	H.P. and V.I.
	Injection		BHP that	Lina	3	H.P. and H.I.
	WAG 1:2 ratio with one-month cycles	Original HCPV of CO ₂ injected and water injection rate based on WAG ratios	the history matched	Drive	4	V.P. and V.I.

Table 10: Summary of the Cases 1-3 of Pattern 10-9

7. CONCLUSIONS AND RECOMMENDATIONS

This thesis has dealt with the evaluation of sweep efficiency in Little Creek Field in order to understand the mechanisms controlling sweep in a late-in-life, continuous injection CO₂ flood and search for alternatives to the way the field was conducted in order to improve recovery. In the first part of this thesis, core analysis and evaluation of heterogeneity effects on reservoir performance were discussed. Dykstra-Parson and Lorenz coefficients were computed pattern by pattern to find a reasonable correlation between oil recovery and CO₂ utilization. There was an expected trend showing that the more the heterogeneity, the higher the amount of CO₂ utilization and the less the amount of oil recovery. The results did not show perfect correlations, but the relationship between heterogeneity measures and reservoir performance values were shown to be statistically significant by using the ANOVA method and the standard t-tests on the significance of the slope of the regression line.

Contrary to the use of field-wide averages, mapping of well by well heterogeneity measures was shown to be a good tool to see geologic trends when compared to traditional maps. The characterization of the main body of the channel in Little Creek Field was performed qualitatively by using heterogeneity measures. The Lorenz coefficient map provided more insight into the reservoir than trying to map permeability, porosity or thickness alone.

The geological trends observed in the Lorenz coefficient maps were then successfully used to adjust rock-types and guide geostatistical modeling of permeability and porosity when performing reservoir modeling and history matching in the second part of the thesis. Two rock regions were defined based on the water production values and the map of the Lorenz coefficients in the pilot area. One of these regions was perceived to be heterogeneous and located outside the main reservoir channel, whereas the other was described as being homogeneous or more specifically of a higher quality. Gravity effects were evaluated by using eight layers in the model. After obtaining successful history matching results, the same method developed in the pilot area was used to assess flood response for the Pattern 10-9 area and again good matches for this particular part of the field were obtained.

One of the main keys to both matches was determining the saturation distribution in the reservoir prior to CO_2 injection. In these window models, this was accomplished by adding injection and production wells located in the larger volume grid blocks along the outer edges of the models. These wells were controlled based on observed operational changes in the field surrounding the window unless there was something within the window area that was specified.

From the pilot area history match, it appears that a fairly large amount of CO₂ moved out of the flood area and was not utilized effectively. Using one of the other pilot area wells that are structurally higher generally allowed more CO₂ to stay in the area of interest. Application of the WAG technique increased recovery in the pilot area with reduced utilization rates. A WAG ratio of 1:2 with one month WAG cycles was found to provide the highest recovery values of those tested. From the solvent saturation maps, flood front stabilization appears to be the reason for the higher recoveries seen in the WAG simulations. Simulations of the GAGD process were highly dependent on well orientation and length. When well orientation and length are correctly determined, the simulations, but were fairly close. Given that Little Creek has low structural relief and high connate water saturation, the fact that GAGD technique may have some application in this type of environment was a bit unexpected. The Pattern 10-9 area simulations showed many of the same characteristics as the Pilot Area simulations. In addition, a five-spot pattern configuration was evaluated. The five-spot showed slightly higher recoveries under continuous injection constraints but with lower initial response rates. Recoveries using the WAG technique at the 1:2 ratio were slightly lower than the current inverted nine-spot simulations.

Recommendations for future work include incorporating any additional injection or production profile logs that may have been run in the field into the geological model. As shown in the Pattern 10-9 area model, this data can have a significant impact on the interpretation of the results. Logs have been run in several other parts of the field. Thus use of the techniques from this thesis should apply to other parts of the field, and should be done. In addition, with current computational capabilities, it may be possible to do a full-field simulation of the Little Creek. Again, techniques from this thesis should provide a good starting point for that work and reduce the time spent integrating data.

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APPENDIX A: PERMEABILITY AND POROSITY VARIOGRAM INFORMATION

		U	8			U				
Permeability										
Layer	1	2	3	4	5	6	7	8		
Number of lags	5	5	5	5	5	5	5	5		
Lag size	840	800	810	860	860	850	860	770		
Search radius	2000	2000	2000	2000	2000	2000	2000	2000		
Variogram type	Gaussian									
Nugget	0	31	0	31	31	31	31	31		
Sill	254	1429	955	2260	2187	4265	5148	1062		
Range	3346	3133	3104	3341	3288	3341	3288	2992		

Table A.1: Pe	rmeabilitv va	riogram i	information	for each	laver in t	the Pilot Area
	•				•	

Table A.2: Porosi	ity variogran	ı information fo	or each laver	in the Pilot Area

Porosity									
Layer	1	2	3	4	5	6	7	8	
Number of lags	5	5	5	5	5	5	5	5	
Lag size	770	850	900	780	810	800	870	920	
Search radius	2000	2000	2000	2000	2000	2000	2000	2000	
Variogram type	Gaussian								
Nugget	0	0	0	0	0	0	0	0	
Sill	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.001	
Range	3065.4	3243	3553	4573	2430	3185	1740	2760	

Permeability									
	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5	Layer 6	Layer 7	Layer 8	
Number of lags	6	6	6	6	6	6	6	6	
Lag size	740	700	890	750	800	840	960	900	
Search radius	2000	2000	2000	2000	2000	2000	2000	2000	
Variogram type	Gaussian								
Nugget	0	0	0	0.011	0	0	0		
Sill	0.056	0.036	0.187	0.115	0.119	0.029	0.042	0.018	
Range	3473	3404	2909	3244	3034	1776	2360	2360	

 Table A.3: Permeability variogram information for each layer in Pattern 10-9

|--|

Porosity									
	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5	Layer 6	Layer 7	Layer 8	
Number of lags	7	7	6	6	7	7	7	6	
Lag size	780	780	1070	750	710	840	840	1000	
Search radius	2000	2000	2000	2000	2000	2000	2000	2000	
Variogram type	Gaussian								
Nugget	0	0	0	0	0	0	0	0	
Sill	0.001	0.001	0.001	0.001	0.002	0.001	0.001	0.001	
Range	3881	3649	2160	2687	1955	1700	2174	3924	
APPENDIX B: INDIVIDUAL WELL HISTORY MATCHES IN PATTERN 10-9

The final history matching results of the cumulative water production for the rest of the wells in Pattern 10-9 is shown in Figures B1 through B4 where the red circles is the observed water production data, and the blue solid line is the simulated water production response.



Figure B.1: Individual Well History Matches for the Cumulative Water Production for Wells 15-1 and 10-9



Figure B.2: Individual Well History Matches for the Cumulative Water Production for Wells 10-15 and 10-10



Figure B.3: Individual Well History Matches for the Cumulative Water Production for Wells 11-5 and 11-13



Figure B.4: Individual Well History Matches for the Cumulative Water Production for Wells 15-2 and 14-4

Although the cumulative water performance is used to show the quality of the match as was done in the pilot area, the simulated water production rates for individual wells are also reasonable with some exceptions. Figures B5 and B6 show the simulated water production rate for each well in Pattern 10-9 during primary and secondary recovery. This model has the same problem as the model of the pilot area, early breakthrough and not quite being able to catch the peak rates. Wells 10-16, 14-4, 15-1 and 15-2 are good examples showing these problems. There might be some incorrect data values especially for the early years. For instance, the sudden increase up to 15,000 bbl/day for the water rate shown in Well 14-4 is certainly questionable. However, in general, the results are still reasonable. Figures B.5 and B.6 show the simulated water production rate for the rest of the wells in Pattern 10-9 during primary and secondary recovery.

The simulated water production rates as compared to actual values and well bottom-hole pressures for individual wells during CO_2 flooding are shown in Figures B.7 through B.12. Note that the simulated water rates match the historical water rates slightly better during the CO_2 flooding part of the history. Also note that bottom-hole pressure values were found to be above the minimum miscibility pressure of 4500 psi for the wells with a dip in late 2001 and early 2002. It was provided by the fake injectors and producers, which had bottom-hole pressure constraints of above 4500 psi during CO_2 flooding. Although the pressure decline started with the oil production in late 2001 and early 2002, most of the wells were again above 4500 psi.



Figure B.5: Individual Well History Matches for the Water Production Rate for Wells 10-8, 11-12, 10-10, 10-7, 10-15 and 10-16 for the waterflood period (1958-1974)



Figure B.6: Individual Well History Matches for the Water Production Rate for Wells 15-1, 10-9, 11-5, 11-13, 15-2 and 14-4 for the waterflood period (1958-1974)



Figure B.7: Water Rate History Match and Bottom-hole Pressure for Wells 10-10 and 10-15 for the CO₂ injection period (1995-present)



Figure B.8: Water Rate History Match and Bottom-hole Pressure for Wells 10-16 and 10-7 for the CO₂ injection period (1995-present)



Figure B.9: Water Rate History Match and Bottom-hole Pressure for Wells 10-8 and 11-12 for the CO₂ injection period (1995-present)



Figure B.10: Water Rate History Match and Bottom-hole Pressure for Wells 11-13 and 11-5 for the CO₂ injection period (1995-present)



Figure B.11: Water Rate History Match and Bottom-hole Pressure for Wells 14-4 and 15-1 for the CO₂ injection period (1995-present)



Figure B.12: Water Rate History Match and Bottom-hole Pressure for Wells 15-2 for the CO₂ injection period (1995-present)

VITA

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