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Department of Mechanical, Aerospace and Civil Engineering College of Engineering Design and Physical Sciences

ENHANCE OIL RECOVERY OF KELLY SNYDER FIELD BY USING CARBON-DI-OXIDE

By

Supervisor:

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[redacted]

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Abstract

Carbon dioxide injection or in other words flooding is one of the EOR techniques in which almost pure Carbon dioxide is injected in to the reservoir which are depleted. The carbon dioxide mixes with the oil in the reservoir and releases from the formation, thus moving the oil to the production well. Carbon dioxide mixed with the oil is separated once the mixture reached to the ground through the facilities available above the ground. The carbon dioxide extracted from the mixture is injected back to the reservoir whereas produced oil is stored for further processing. The carbon dioxide EOR techniques have attracted the new market. The very first carbon dioxide EOR was tried in Scurry County in Texas in the year 1972. The initial exercise of carbon dioxide was very successful throughout the Permian basis. Interfacial tension is disappeared when injected CO_2 and the crude oil are miscible. Therefore it is possible to displace the oil from the rock pores by using the CO_2. Oil swells when CO_2 is dissolved in the oil which also reduced the viscosity of the oil. Reduction in viscosity helps the displacement activity and finally increases the process efficiency. When volume of carbon dioxide is injected in the well, alternated with the water volume then the concept is known as carbon dioxide flooding, it is also recognized by the abbreviation WAG floods- Water Alternating Gas. The advantage of WAG flood is that it helps to ease the tendency of carbon dioxides lower viscosity which figures its path ahead of the displaced oil.

This paper is primarily focused on the Kelly Snyder field, the reservoir data is obtained from the various sources and this data is used to study the effect of injecting carbon dioxide into the reservoir. The two scenarios have been tested in this work, one before the carbon dioxide EOR and the other is after implementing carbon dioxide EOR. The paper represents the model of Kelly Snyder oil filed which is situated in County Scurry in Texas. The material balance method is used in MBAL software tool which predict production forecast in terms of the production performance.

The results of reservoir simulation shows the incremental recovery factor, daily oil rate, oil recovery factor as well as oil production profile prediction. The results obtained from the simulation is compared with each other and actual field data found through web research

to understand and analyze the similarities as well as discrepancies. The probable reasons of similarities and discrepancies are discussed in discussion chapter. The conclusion chapter gives further recommendation to close the gap between the simulated results and actual scenario.

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Nomenclature

API	American Petroleum Institute
BCF	Billion Cubic Feet
EOR	Enhance Oil Recovery
F	Fahrenheit
GOR	Gas to Oil ratio
IOR	Improved oil recovery
MBAL	Material Balance Analytical Simulation Tool
MMscf/D	Million standard cubic feet per day
MMSTB	Million stock tank barrels
MSTB/D	Thousand stock tank barrels per day
OOIP	Original Oil in Place
PVT	Pressure Volume Temperature
SACROC	Scurry Area Canyon Reef Operators
SCF	Standard cubic feet
SPE	Society of Petroleum Engineers
STB	Standard stock tank barrel
STB	Stock tank barrel

Contents

Chapter 1: Introduction

Reducing the dependence on foreign energy source and reducing the emission of greenhouse gases are the two main challenges the United States of America is facing at this moment. These challenges has increased the attention to the topic of carbon dioxide (CO_2) enhanced oil recovery. The carbon dioxide enhanced oil recovery has been practiced by the oil and gas industry since more than 35 years. The process includes capturing, producing, transporting and using it for injection for the recovery of the oil.

Basic Concept of carbon dioxide oil recovery,

Injection of Carbon dioxide (CO_2) into the pores in rocks helps to move crude oil out. The two characteristics of the carbon dioxides make it as an excellent choice for this purpose.

- Carbon dioxide is miscible with crude oil
- Carbon dioxide is very cheap as compared to other miscible fluid

For an instance, consider, tools used while working on the motor bikes engine got oily on its surface. Now consider washing the tools with water, very little oil will be washed off but now consider washing with oil and soap, it will do better job than water but solvents are better than these two options, solvent removes every drop of oil from the surface of the tool. The reason of this is, solvent makes homogeneous mixture with oil as it mix well with it and wash away oil from the surface of the tool. Therefore mixture of ethanol and water, vinegar and water are known and used as degreaser. Another example is motor oil, it shows miscibility which means ability of oil to mix in all proportion. We know that oil and water cannot mix with each other therefore they called as immiscible therefore it is difficult to remove oil from tool with water alone and it needs solvent to do the job. It is possible to use similar solvent to extract the oil from underground reservoir. Unfortunately these miscible solvents are relatively expensive as they are produced from reservoir oil. Therefore it is difficult to use these solvent in perspective of economic sense even if they are effective. Similarly for the natural gas for an example, propane; it can be mixed with oil but the oil is expensive commodity whereas deposits of CO_2 which id underground is relatively cheap. Therefore it is possible to extract large quantities of naturally occurring gas, which is sensible choice.

It is possible to use captured CO_2 from human activities as a source, which is comparatively inexpensive. When injected in the oil reservoir, carbon dioxide mixed with residual crude oil as a light hydrocarbon form. Oil dissolves in the CO_2 and CO_2 dissolves in to the oil. This activity happens rapidly due to high density of CO_2 when it is compressed and due to the significant lower carbon (light hydrocarbons) contents in oil, in other words low density crude oil. CO_2 and oil is not miscible below minimum pressure. The reason could be the temperature decrease, the density of CO_2 decreases or the density of the oil increases due to fraction of light hydrocarbons decreases. Therefore it is necessary to maintain the minimum pressure to ensure the miscibility of oil and CO_2. Because of this reason it is necessary to consider the pressure of the used oil reservoir by the oil field engineer while considering the oil reservoir well for carbon dioxide enhanced oil recovery. It is possible to re-pressurize the low pressurized well by injecting the water. Interfacial tension is disappeared when injected CO_2 and the crude oil are miscible. Therefore it is possible to displace the oil from the rock pores by using the CO_2. Oil swells when CO_2 is dissolved in the oil which also reduced the viscosity of the oil. Reduction in viscosity helps the displacement activity and finally increases the process efficiency. When volume of carbon dioxide is injected in the well, alternated with the water volume then the concept is known as carbon dioxide flooding, it is also recognized by the abbreviation WAG floods- Water Alternating Gas. The advantage of WAG flood is that it helps to ease the tendency of carbon dioxides lower viscosity which figures its path ahead of the displaced oil.

Background of CO_2 injection

The study shows that oil and gas sector is more focused on finding new oil and gas field. Most of the renowned oil and gas exploration companies are doing exactly the same, drilling for new oil and gas field to earn their profits. In contrast, there is a sub sector within oil and gas sector which is entirely focused on improving the life of the already exists oil and gas producing fields, It means producing more oil from the existing fields than forecasted in the beginning. The share of this sub sector is larger than the oil exploration companies. Unlike exploration companies which are primarily focused on drilling, these sub sector companies are very well recognized as production organization. The primary requirement of these production organization companies is to pursue the large set of engineering skills as they are always focused on recovering more and more oil from depleted reservoirs which is also known as 'reluctant reservoirs'. To achieve additional extraction it is necessary to use advanced recovery techniques. The success in terms of finance or profits coming to these production organizations are slower as the cost per barrel using advanced recovery approach is more. Very few companies have chosen the path of enhanced oil recovery and opted the focus from exploration and drilling as the business plan focused on advanced oil recovery leads to considerably huge oil reserves and long life of production. On the other hand most of the companies are focused on exploration business plan to provide quick profit to its shareholders due to continuous competition in the market (Melzer, L. 2012).

Below are the phases of oil production, it is useful to provide the background for the research work. It is arranged in a framework to understand oil and gas production within the actual industry.

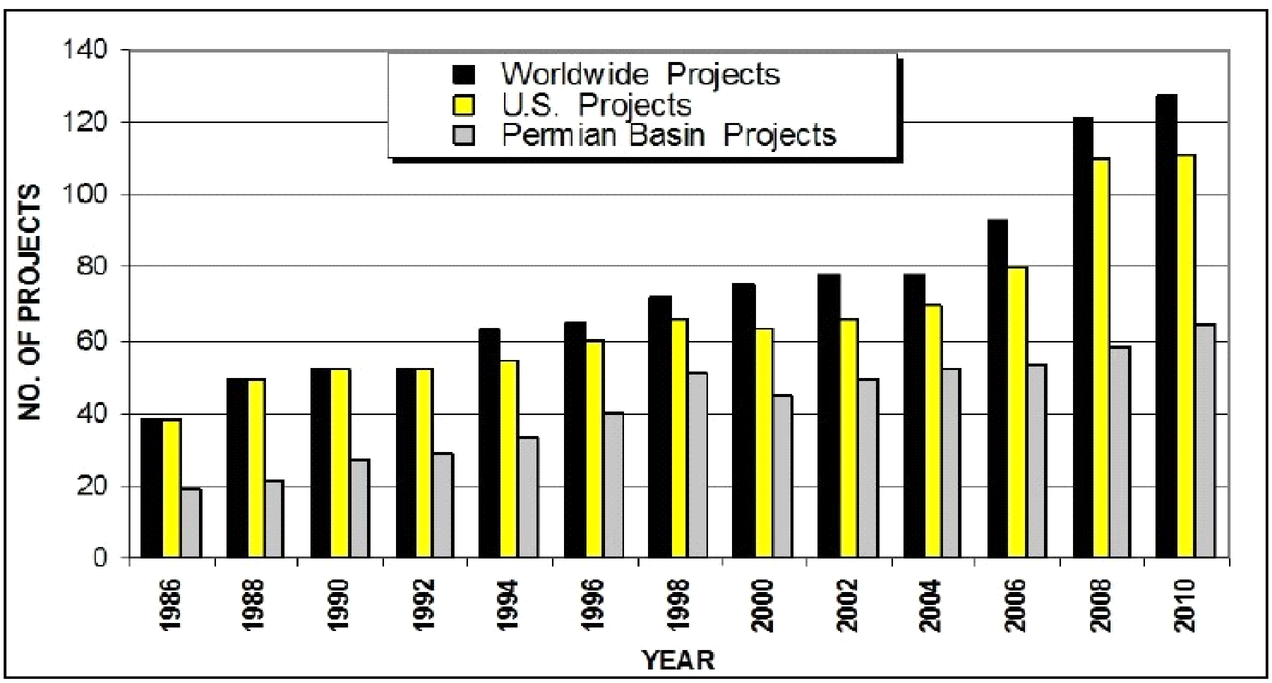
Primary production phase- The very first production phase of the reservoir is called as primary production phase. In this phase, the new field is explored and well is being formed by drilling into the formation. By using the pent up energy of the fluids within the reservoir rock oil or gas is produced. Reservoir rock is usually a carbonate (limestone, dolomite) or sandstone formation. The financial returns in the primary phase come quickly as the fluid pressure in the reservoir is very high and if the exploration companies are experienced in finding new gas or oil fields and avoiding producing dry holes. When there is a reduction in reservoir pressure which is being used as energy to extract oil or gas the well eventually stops to produce the fluid. This stage is known as artificial lift, in this stage fluids are lifted or in other words pushed to the exterior and production can be extended. After sometime, well produces volumes which is known as uneconomic volumes due to the very low pressure which does not allow fluid to move within the formation to the well bore. Reduced pressure does not mean that reservoir has minimal oil, even at this point considerable amount of fluid is trapped within the reservoir, and study shows that trapped amount could be close to 80 to 90%. The fluid is mainly trapped between the spaces and pores of the rock (Melzer, L. 2012).

Secondary Phase of Production- There are two options after depletion of the reservoir fluid pressure, abandoned the reservoir or convert it in to the secondary phase of production. In secondary phase production substance is injected in to the reservoir to re-pressure the reservoir formation. Usually water is used as a substance. To inject water in the reservoir, either one of the existing well is used or new wells are drilled to facilitate the injection. Once the water is injected in the well then it sweeps the oil to the producing well. It has been found that the secondary phase of production is very productive and can extract almost equal or even more volume of reservoir fluid as compared to primary phase of production (Melzer, L. 2012).

As mentioned earlier, water is used as a substance to inject in to the reservoir in the secondary phase of production. The main reason of injecting water is, it is relatively cheap. Usually fresh water is not used during the injection which has been proved effective in current practices. The water produced from the extraction is recycled back in to the reservoir repeatedly. Unfortunately even in this phase of production 50 to 70% of the oil that was discovered at the time of exploration remain in the reservoir after the water injection as water and oil does not mixed well together and the oil is bypassed by the water.

Tertiary Production Phase- The third phase of production is implemented when the company aims to extract remaining oil from the reservoir which is left after the water flooding. The tertiary phase of production involves use of injectant such as carbon dioxide (CO_2) which helps to change the properties of the reservoir fluid, crude oil in this case which enable it to flow without restrictions within the reservoir. Some of the injectant are, hot water or chemicals or simple heat can facilitate the objectives. This technique of enhancing the productivity of the depleted reservoir is classified in to a category known as enhanced oil recovery (EOR). One of the most successful method is carbon dioxide flooding (CO_2- EOR). Pure carbon dioxide which has greater 95% all of the three components has the properties to mix well with the oil and make it lighter, swell it, it allows oil to detach from the surface of the rock and allow it to flow freely in the reservoir. This free flowing oil then swept up in the flow from the injector to producing well. Commercial testing of this technique was carried out in the 1970's in the Permian Basin of West Texas and Southeastern New Mexico. Very first two large scale project involving SACROC flood and Crossett flood implemented in Scurry County in Texas in January 1972 and Crane/ Upton counties in April 1972 respectively. It is necessary to note that installation and commissioning of these two flood project were encouraged and motivated by daily production allowable to relief offered through experimental procedures by the 'Texas Road Commission and Special Tax treatment of oil' (Melzer, L. 2012).

Petroleum industry concluded that the incremental oil can be produced by injecting carbon dioxide in the oil reservoir over the next five to ten years. Thus number of carbon dioxide EOR began to grow. Figure 1 below illustrate the growth of carbon dioxide EOR since 1984 till 2010. The projects are still increasing till date to extract more and more oil from depleted field.



Graph 1: Worldwide, USA and Permian basin CO_2 EOR project counts

Figure 2 below shows the first carbon dioxide project for the natural gas processing. It was sold in the south region of the Permian Basin as shown in Figure 2 below.

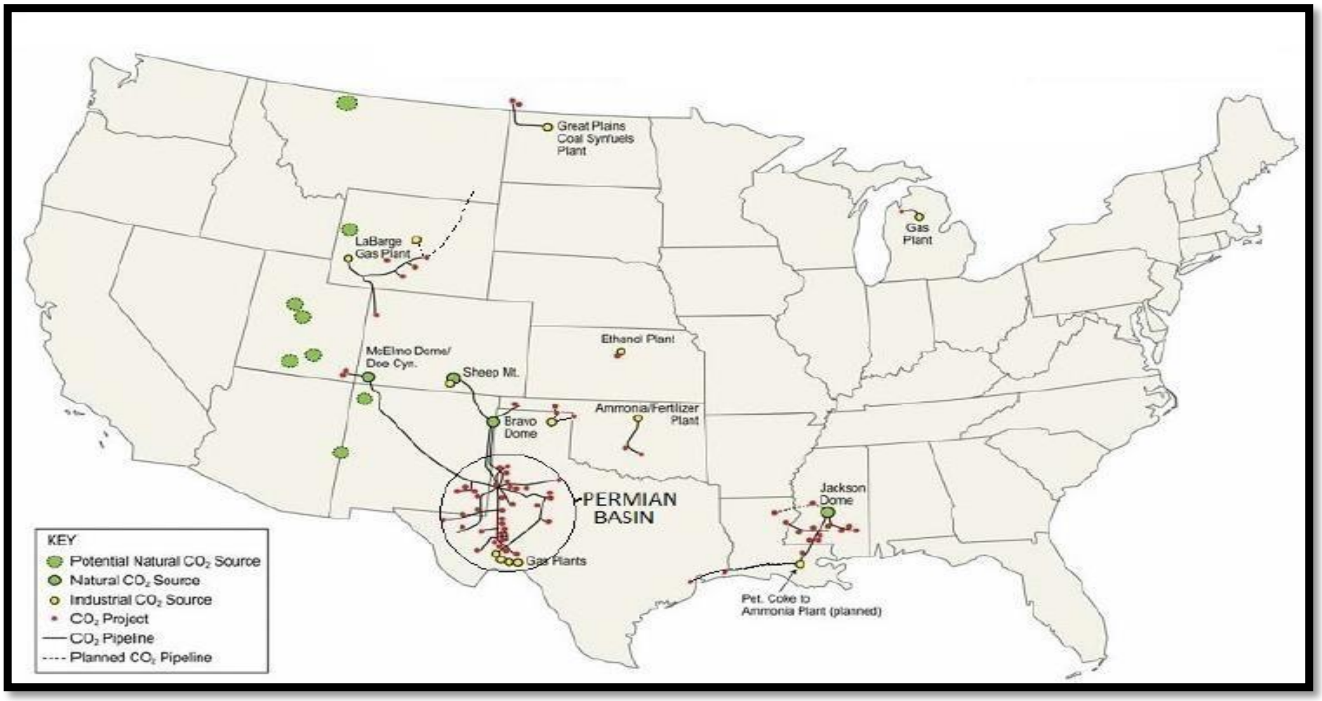


Figure 1: Infrastructure of USA pipeline and injection site

Now companies are conscious about the source of naturally occurring fields which gives considerably pure form of carbon dioxide, that have capability to offer huge quantity of carbon dioxide. Three sources of carbon dioxide were developed namely Bravo Dome in northeastern New Mexico, Sheep Mountain in south central Colorado and McElmo Dome in southwestern Colorado. Infrastructure and the pipeline were constructed in the 1980’s, which facilitate the connection of source of carbon dioxide field with the oil field in Permian Basin. The growth of carbon dioxide EOR projects were seen in early 1980’s due to the new supply of carbon dioxide, this also expands in to other regions of the United States. The oil prices drops to single digits due to the crash in oil prices in 1986 it was units of $/bbl in many counties. Due to crash in oil prices affects the economics of the flooding for the oil, therefore capital for new projects was absent. Although EOR projects survived due to the sub industry based on long term nature of advance oil recovery. The figure 1 shows the surviving EOR projects during the crash with minor effects and sustainable growth curve can be seen until 1998 which was the next price crash.

CO_2 EOR activity in the USA

The recent 10 years has shown improvement in new CO_2 floods projects. Altogether, 111 CO_2 EOR projects are underway in the United States, from which 64 are in the Permian Basin. This number is doubled since the year 1998, as the economy for the flood projects was crippled due to the price crash in year 1998. In the Rockies, Mid-continent region and Gulf Coastal regions new CO_2 pipelines are being built. These new pipelines facilitate flooding activity dramatically. It has been seen that the daily CO_2 volumes have been sold effectively in Permian Basin. Due to this prices of CO_2 have reached record high and presently it is approaching half the price of natural gas.

The aggregate production of oil through CO_2 EOR has improved to 18% of the total oil production of the Permian Basin, in other words, 180,000 out of 1,000,000 bopd (barrels of oil per day). This figure also compares to approximately 5% of the daily United States oil production. The oil companies are therefore declares to find new barrel oil field through CO_2 EOR. It is difficult to find a new oil field today within United States. It is necessary to note that the in the year 2005 United States has produced billionth US CO_2 EOR barrel. In United States the volume of CO_2 bought and sold every day is 3.1 billion cubic feet or in other term 65000000 tons per year.

Aim and objectives of the research

Aim of this thesis is to examine the technical and the economic potential of applying CO2-Enhanced Oil Recovery in the Permian Basin oil reservoirs.

The thesis objectives are set out as below to achieve the aim of the project,

- To conduct background research and literature review
- To study reservoir geology and fluid parameter of Kelly-Snyder oil field
- To understand the process of CO_2 injection process
- To conduct the simulation by using the software MBAL
- Compare the existing output of the oil field with the results obtained through simulation

Outline of the research

The CO_2 enhanced oil recovery is gaining importance due to increasing demand and reducing level of oil reservoir. CO_2 enhanced oil recovery is one of the many ways to recover the oil which is stick to the rocks deep down the oil well.

Below is the list of chapter along with their brief overview.

Chapter 1: This chapter describes the background of CO_2 EOR along with the important phases of reservoir. This chapter also discuss CO_2 EOR activity in brief. Aim and objectives of the thesis are listed in chapter 1.

Chapter 2: Literature review chapter discusses writings of different authors in regards with CO_2 EOR especially Enhanced oil recovery (EOR) its methods emphasizing on CO_2 EOR. Screening criteria is discussed for different EOR methods along with CO_2 EOR. Different properties of CO_2 and their benefits for EOR are elaborated for better understanding. This section provide different injection mechanism by using CO_2 gives an idea behind the CO_2 EOR and its principles. Advantages as well as limitations have been discussed along with different processes of miscible and immiscible CO_2 EOR processes.

Chapter 3: This chapter is a case study on Kelly Snyder oil field. It mainly focus on history of the Kelly Snyder field, its geology, reservoir parameters, fluid parameters, oil in place, Number of producing wells, Number of injectors that have been used since the inception, recoverable reserves and oil production profile. A small case study of pattern injection is conducted within production profile to understand the actual mechanism of the CO_2 EOR in Kelly Snyder field. Different strategies along with challenges have been discussed in this section which is followed by conclusion.

Chapter 4: This chapter illustrate the results obtained through MBAL simulation software. The chapter begins with the brief introduction of MBAL software with its advantage over conventional material balancing methods, which is followed by the graphs obtained before implementing CO_2 EOR and after implementing CO_2 EOR. The prediction of oil production results are provided in appendices in tubular format.

Chapter 5: This chapter mainly discusses the graphs obtained through MBAL simulation software before and after implementing CO_2 EOR. This section also discuss the difference in parameters obtained through MBAL software and actual production profile of the Kelly Snyder field. The parameter discusses are, oil in place, Number of producing well in actual and simulated conditions, Number of injectors, recoverable reserves, production profile and the rate of production per day.

Chapter 6: This chapter concludes the thesis by comparing the results obtained through the MBAL software to emphasize on benefits of CO_2 EOR. This chapter also provides recommendations for the future work in the same field.

Reference: All the references are listed in the Harvard referencing style.

Appendices: All the additional data such as graphs, tables are incorporated in appendices which will be useful to reader to take reference from.

Chapter 2: Literature review

Introduction to EOR using CO_2

The use of carbon dioxide injection method for enhanced oil recovery has a history more than 60 years. Whorton Brownscombe was the first person who came up with this idea and received the patent for carbon dioxide enhanced oil recovery in the year 1952 (Brownscombe, W 1952). The pilot project was carried out in the Mead Strawn field in the year 1964 where carbon dioxide was injected in to the oil reservoir, the pilot project proved to be successful as the injection of carbon dioxide improved the production of oil (Holm, 1971). The first commercial carbon dioxide injection enhanced oil recovery project was started in 1972 at the Kelly Snyder oil field in the United States of America (Langston et. al, 1988). The numbers of carbon dioxide enhanced oil recovery projects have increased in the United States and in the world since the successful commissioning of the first commercial carbon dioxide enhanced oil recovery project at the Kelly Snyder oil field. According to survey conducted by Leena Koottungal shows that, number of carbon dioxide enhanced oil recovery projects on the earth has reached 136 by May 2014 (Koottungal, L. 2014)

According to recent survey conducted by Leena Koottungal in the year 2014 shown in table 1 shows the global scenario of carbon dioxide enhanced oil recovery project in the world (Koottungal, L. 2014).

From the table, it can be seen that most of the carbon dioxide enhanced oil recovery projects are located in North America and that is in the United States of America. Total number of CO_2 EOR projects in the USA at the beginning of 2014 were 128 whereas total number of projects commissioned in the world are 154 which includes, USA with total 139 projects, Canada with 6 projects, Brazil is with 3 projects, Trinidad is with 5 projects, and Turkey is with 1 project. It can be also observed that the miscible carbon dioxide enhanced oil recovery projects are more popular and installed in many locations as compared with immiscible carbon dioxide enhanced oil recovery project. It can be also observed that the miscible carbon dioxide enhanced oil recovery projects are more popular and installed in many locations as compared with immiscible carbon dioxide enhanced oil recovery project.

Table 1: Global Scenario of CO_2 EOR projects till beginning of the 2014 (Koottungal, L. 2014)

Country	Number of miscible CO2 EOR projects	Number of immiscible CO2 EOR projects	Total number of CO2 EOR projects
USA	128	11	**139**
Canada	6	0	**6**
Brazil	2	1	**3**
Trinidad	0	5	**5**
Turkey	0	1	**1**
Total	**136**	**18**	**154**

It can be also observed that the miscible carbon dioxide enhanced oil recovery projects are more popular and installed in many locations as compared with immiscible carbon dioxide enhanced oil recovery project. Most of the immiscible carbon dioxide EOR projects are installed in the USA which sum up to 11 which is followed by Trinidad which is 5 (Koottungal, L. 2014). From the Survey it has been found that most of the carbon dioxide enhanced oil recovery projects are installed in the United States of America and Canada, as both of these countries have ample amount of natural resources of carbon dioxide (CO_2) (Sohrabi et al., 2009). Even though cost of CO_2 is cheap but the logistics of CO_2 is costly that makes the overall cost of CO_2 high (Gozalpour, 2005).

The advanced resources international and IEA greenhouse as R & D conducted a research to study the global potential for carbon dioxide enhanced oil recovery programme. To test the potential of carbon dioxide enhanced oil recovery, the agency carried out survey on 54 largest oil basins (IEA Greenhouse Gas R&D Programme, 2009). The methodology carried out for the study is based on the similar experience of the United States of America (U.S. Department of Energy/National Energy Technology Laboratory, 2010). It has been found that from the results of the assessment that 50 oil basins out of 54 are suitable to implement carbon dioxide enhanced oil recovery projects. It was predicted that, these oil basins could produce around 470 billion barrels of oil which is additional to their existing capacity and able to store carbon dioxide up to 140 billion metric tons by using advanced carbon dioxide enhanced oil recovery technology. Through different surveys it has been found that, even if the smaller oil fields in the world are switched to carbon dioxide enhanced oil recovery method then additional 1 trillion barrels of oil could be recovered along with storage of 320 billion metric ton of carbon dioxide by using advanced carbon dioxide enhanced oil recovery technology everywhere in the world (Advanced Resources International, Inc., 2011).

Screening criteria of EOR methods

Different screening criteria's are used for different enhanced oil recovery method. The screening criteria for different EOR are shown in table 2 (Taber et al., 1997).

Table 2: Screening criteria for different enhanced oil recovery methods (Taber et al., 1997)

		Oil Properties			Reservoir Characteristics					
Detail Table in Ref. 16	EOR Method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
				Gas Injection Methods (Miscible)						
1	Nitrogen and flue gas	>35 ↗ $\underline{48}$ ↗	<0.4 ↘ $\underline{0.2}$ ↘	High percent of C_1 to c7	>40 ↗ $\underline{75}$ ↗	Sandstone or carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	>23 ↗ $\underline{41}$ ↗	<3 ↘ $\underline{0.5}$ ↘	High percent of C_2 to C_7	>30 ↗ $\underline{80}$ ↗	Sandstone or carbonate	Thin unless dipping	NC	>4,000	NC
3	CO_2	>22 ↗ $\underline{36}$ ↗ [a]	<10 ↘ $\underline{1.5}$ ↘	High percent of C_5 to C_{12}	>20 ↗ $\underline{55}$ ↗	Sandstone or carbonate	Wide range	NC	>2,500[a]	NC
1–3	Immiscible gases	>12	<600	NC	>35 ↗ $\underline{70}$ ↗	NC	NC if dipping and/or good vertical permeability	NC	>1,800	NC
				(Enhanced) Waterflooding						
4	Micellar/ Polymer, ASP, and Alkaline Flooding	>20 ↗ $\underline{35}$ ↗	<35 ↘ $\underline{13}$ ↘	Light, intermediate, some organic acids for alkaline floods	>35 ↗ $\underline{53}$ ↗	Sandstone preferred	NC	>10 ↗ $\underline{450}$ ↗	>9,000 ↘ $\underline{3,250}$	>200 ↘ $\underline{80}$
5	Polymer Flooding	>15	<150, >10	NC	>50 ↗ $\underline{80}$ ↗	Sandstone preferred	NC	>10 ↗ $\underline{800}$ ↗ [b]	<9,000	>200 ↘ $\underline{140}$
				Thermal/Mechanical						
6	Combustion	>10 ↗ $\underline{16}$ → ?	<5,000 ↓ $\underline{1,200}$	Some asphaltic components	>50 ↗ $\underline{72}$ ↗	High-porosity sand/ sandstone	>10	>50[c]	<11,500 ↘ $\underline{3,500}$	>100 ↗ $\underline{135}$
7	Steam	>8 to $\underline{13.5}$ → ?	<200,000 ↓ $\underline{4,700}$	NC	>40 ↗ $\underline{66}$ ↗	High-porosity sand/ sandstone	>20	>200 ↗ $\underline{2,540}$ ↗ [d]	<4,500 ↘ $\underline{1,500}$	NC
—	Surface mining	7 to 11	Zero cold flow	NC	>8 wt% sand	Mineable tar sand	>10[e]	NC	>3 1 overburden to sand ratio	NC

NC = not critical.
Underlined values represent the approximate mean or average for current field projects.
[a]See Table 3 of Ref. 16.
[b]> 3md from some carbonate reservoirs if the intent is to sweep only the fracture system.
Transmissibility > 20 md-Wcp
[d]Transmissibility > 50 md-Wcp
[e]See depth.

It is necessary to note that the application of carbon dioxide enhanced oil recovery is not recommended for all of the oil fields in the world due to economic as well as technical reasons. According to (Shaw et. al, 2002) it is necessary to evaluate the technical suitability of oil field/ reservoir for carbon dioxide enhanced oil recovery as well as storage before considering the economic criteria. In the beginning screening should be done for suitability for carbon dioxide enhanced oil recovery and the storage which is then followed by the technical ranking of the suitable reservoir. At the end the capacity of Carbon dioxide storage and carbon dioxide enhanced oil recovery should be forecasted. Table 3 shows different criteria proposed by different authors according to their research, experience and the optimization of the performance of carbon dioxide enhanced oil recovery. This table is compiled by (Shaw et. al, 2002).

Table 3: screening criteria for application of CO2- EOR by various authors (Shaw et. al, 2002)

Reservoir Parameter	Geffen (1973)	Lewin et al. (1976)	NPC (1976)	McRee (1977)	Jyoho (1978)	OTA (1978)	Carcoana (1982)	Taber&Martin (1983)	Taber et al. (1997a)
Depth(ft.)		> 3,000	> 2,300	> 2,000	> 2,500	i) > 7,200 ii) > 5,500 iii) > 2,500	< 9,800	> 2,000	i) > 4,000 ii) > 3,300 iii) > 2,800 iv) > 2,500
Temperature (℉)		NC	< 250				< 195	NC	
Original pressure(psia)	> 1,100	> 1,500					> 1200		
Permeability (mD)		NC		> 5	> 10		> 1	NC	
Oil gravity (°API)	> 30	> 30	> 27	> 35	30-45	i) < 27 ii) 27-30 iii) > 30	> 40	> 26	i) 22-27.9 ii) 28-31.9 iii) 32-39.9 iv) > 40
Viscosity(cP)	< 3	< 12	< 10	< 5	< 10	< 12	< 2	< 15	< 10
Fraction of oil remaining	> 0.25	> 0.25		> 0.25	> 0.25		> 0.30	> 0.30	> 0.20

The shown criteria in the table does not need to be matched in all the cases as some of them are affected by other factors and can be ignored. For an instance, oil viscosity and depth of the reservoir can be ignored as they are related to other parameters such as reservoir temperature and oil gravity. Use of these criteria helps to evaluate the suitability of the carbon dioxide enhanced oil recovery method to a specific oil field which is mainly depending upon the general properties of the reservoir as well as oil; it also helps in decision making (Shaw et. al, 2002).

The study carried out by (Rivas et. al, 1992) on reservoir parameters which affects the performance of carbon dioxide enhanced oil recovery as well as the results which exist the set of optimum values of the reservoir properties and the oil, that guarantees the best performance of carbon dioxide enhanced oil recovery. Table 4 shows these optimum values along with the weighting factor (relative performance) is illustrated in the table 4 as well. During analysis and evaluating the properties of the oil field/ reservoir, the farthest value from the optimum value of the parameter is known as the worst value. It is necessary to note that the existence of the worst value in evaluation is accepted but one worst value should be above the optimum value of the parameter and the other worst value should be lower than that of optimum value (Rivas et. al, 1992).

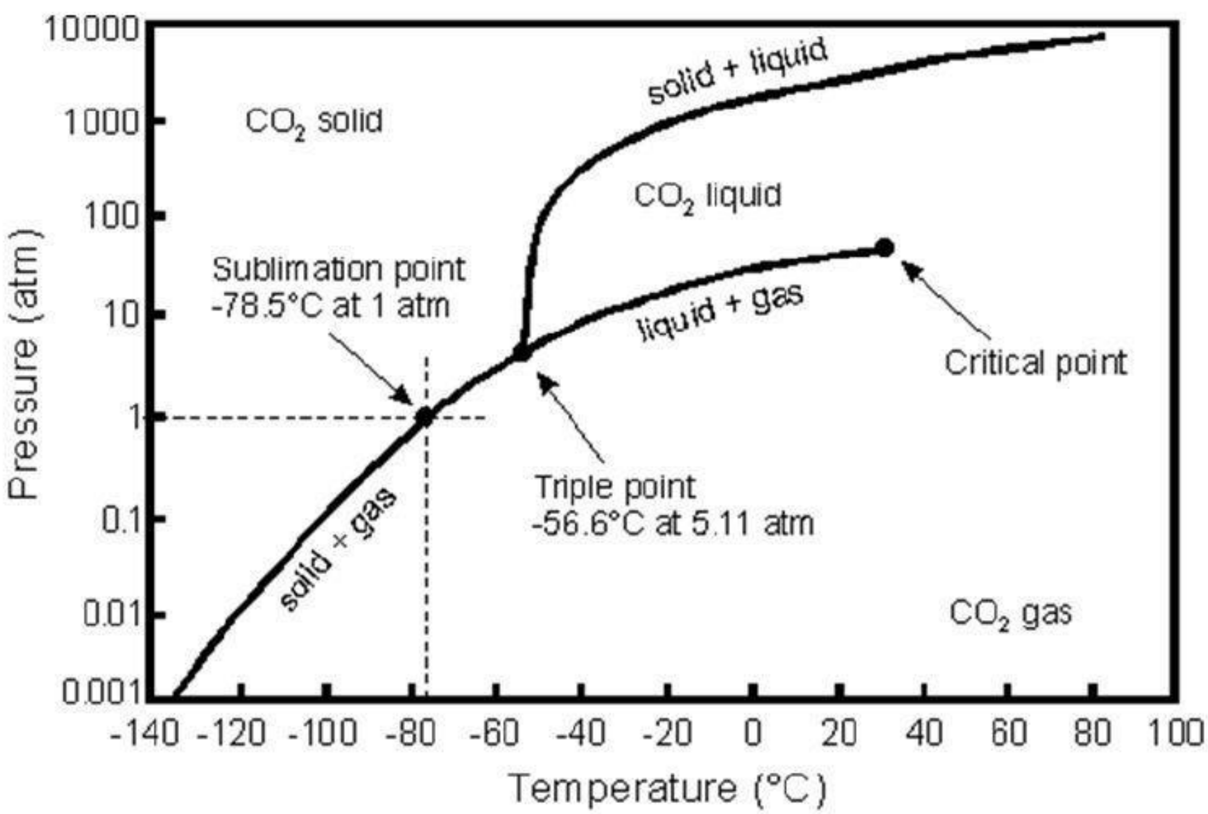
Table 4: Optimum reservoir parameter for carbon dioxide enhanced oil recovery (Rivas et. al, 1992)

Reservoir parameters	**Optimum Values**	**Parametric weight**
API gravity (^{0}API)	37	0.24
Remaining oil saturation	60%	0.20
Pressure over MMP (MPa)	1.4	0.19
Temperature (^{0}C)	71	0.14
Net oil thickness (m)	15	0.11
Permeability (mD)	300	0.07
Reservoir dip	20	0.03
Porosity	20%	0.02

There are three performance parameters are mainly considered for the performance of the specific oil reservoir and those are, Carbon dioxide enhanced oil recovery factor, OOIP and capacity of carbon dioxide storage. All these three factors are critical. However the final decision is affected by several other factors such as surface facilities, cost and availability of carbon dioxide as well as other economic factors (Rivas et al., 1992).

Properties of CO_2

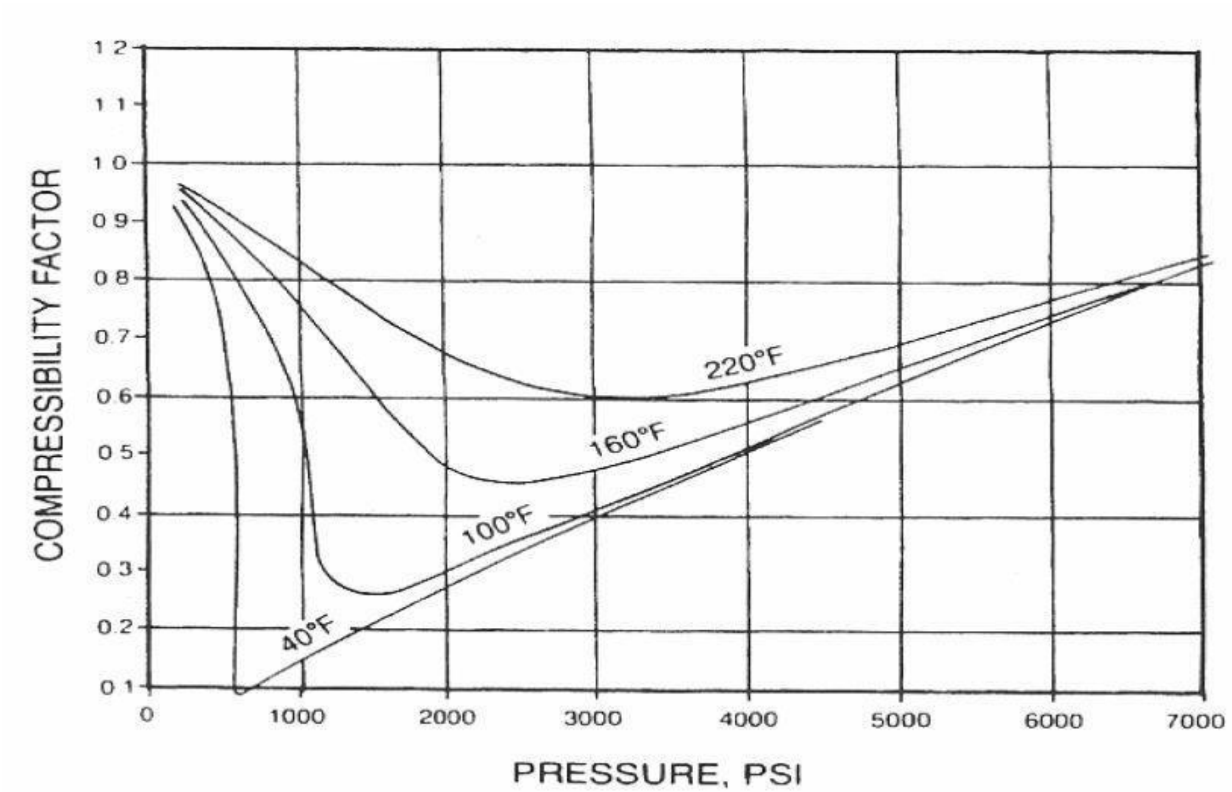
It is required to understand the properties of carbon dioxide, specifically physical properties of carbon dioxide in order to improve carbon dioxide enhanced oil recovery performance.



Graph 2: Phase diagram of carbon dioxide (Picha, 2007)

Figure 3 shows the properties of carbon dioxide in a phase diagram in very simplistic way possible (Picha, 2007). The critical pressure is about 70 bar and critical temperature is 30

^0C which is shown in the phase diagram by critical point. Critical point and these two values have great importance and the interest as the area above critical temperature as well as critical pressure is known as supercritical zone, in that area carbon dioxide is in super critical condition. According to (Sage, 1955), critical temperature of carbon dioxide is 31 ^0C precisely where as critical pressure in 73.825 bar which is equivalent to 72.3485 atm. 464 Kg/m^3 is the critical density of carbon dioxide. Phase diagram shows the triple point of carbon dioxide which is one of the important points as well. From the phase diagram, the triple point temperature is -56.6 ^0C and the pressure at triple point is 5.185 bar. Specific gravity of carbon dioxide is 1.521 whereas the molecular weight is 44.01 g/mol at the temperature 15 ^0C and pressure of 1.013 bar. The density is 1.87 kg/m^3 at 1.013 bar and at 15 ^0C whereas the compressibility factor Z is 0.9942 at 1.013 bar and at 15 ^0C (Sage, 1955). It is necessary to note that the density of carbon dioxide in many reservoirs is similar to the oil in reservoir. In some scenarios it has been found that the density of the carbon dioxide is either smaller or greater than that of oil in reservoir. The degree of the densities of the both carbon dioxide as well as the oil is dependent on the temperature of the reservoir, pressure of the reservoir and the composition of the oil. As discussed earlier that the logistics of the carbon dioxide is critical issue therefore compressibility of the carbon dioxide is to be considered as well as it is related to the transportation as well as the supply. Figure 4 below shows the relationship between the compressibility and pressure as well as temperature.



Graph 3: Compressibility factors of carbon dioxide (Sage, 1955)

From the figure above it can be clearly observed that the compressibility of the carbon dioxide increases with pressure of carbon dioxide. On the other hand relation between compressibility and temperature is more complicated as compared to relation between compressibility and pressure. In nutshell, compressibility of carbon dioxide decreases with the increase in temperature till the turning point, which is the lowest point on the curve of compressibility. Now from this turning point compressibility starts to increase with the increase in temperature of carbon dioxide (Sage, 1955)

Injection of CO_2 mechanism in EOR

Incremental oil recovery can be achieved by using different mechanisms of carbon dioxide enhanced oil recovery method. The mechanisms are illustrated below, (Tzimas et al., 2005; Haynes et al., 1990; Gozalpour et al., 2005; Advanced Resources International, Inc, 2010; Andrei et al., 2010)

a) Oil swelling- Once carbon dioxide is injected in the oil reservoir, carbon dioxide increases the volume of the oil in reservoir. This expansion of oil improves the mobility of the reservoir oil which helps the oil to flow from the reservoir to the well of production. It is necessary to note that the larger oil expansion helps to avoid wastage of the oil or in other words lees amount of the residual oil remain in the well.

b) Reduction of the viscosity of the oil- The viscosity of the oil in reduces realty once carbon dioxide is injected in the reservoir and it saturated in the oil. The reduction in viscosity results in improved mobility of the oil which helps the production well to extract more oil. If viscosity of the reservoir oil is very high then the amount of viscosity reduced is more. Therefore it can be easily conclude that the dissolution of carbon dioxide in heavy crude oil is more than that of light crude oil hence the viscosity reduction in heavy crude oil is more than that of light crude oil. Therefore it is always recommended that, carbon dioxide is very good choice to recover heavy crude oil from the reservoir. The pressure plays crucial role in this formation, as the high pressure in the well helps carbon dioxide to dissolve in the crude oil which helps to achieve significant reduction in oil viscosity.

c) Reduction in the mobility ratio- When carbon dioxide is injected in the reservoir, carbon dioxide dissolves in the water which improves the viscosity of the water therefore mobility of the water improves. On the other hand mobility of the reservoir oil is realty affected and it decreases. The result of this action reduces the mobility ratio between the oil and water which helps to improve the stability of the fluid flow and increases the volumetric sweep efficiency of the well.

d) Reduction in the interfacial tension between water and oil- Once carbon dioxide injected in the oil reservoir, the interfacial tension between water and oil reduces. The decrease in interfacial tension improves the fluid flow which helps to achieve incremental oil production.

e) Extraction of light oil component and its vaporization- The light hydrocarbons have affinity towards carbon di oxide and are intersoluble in carbon dioxide. Pressure plays important role, at certain pressure these hydrocarbon based on their properties and the temperature of the crude oil can be extracted by carbon dioxide and vaporize the light oil component from oil reservoir. This phenomenon is observed especially in recovery of the light oil or hydrocarbons. Carbon dioxide enables the extraction and vaporization of the light hydrocarbons in the reservoir oil is one of the important mechanisms of using carbon dioxide injection which help to improve the productivity.

f) Effect of weak acid- Carbonic acids forms due to the mixture of the carbon dioxide and the water which can react with the carbonates present in the reservoir rocks. Reservoir rock might be corroded due to the reaction which helps to improve the permeability of the reservoir well. In addition to that the mixture of carbon dioxide and water clears the obstruction of the inorganic scale and helps to open the oil flow passage which helps to improve production of the oil.

g) Solution as drive- Due to increase in injection pressure during the process of injection carbon dioxide dissolves in the crude oil in maximum quantity. The pressure in reservoir well reduces once the injection of the carbon dioxide is ceased and it continues to reduce with the oil production. Due to reduction of the pressure, dissolved carbon dioxide in the oil separates from the oil and it forms the gas drive solution which improves the oil flow by providing the energy. This gas drive solution is closely similar to the natural gas drive solution. Additionally, after displacement of the oil, carbon dioxide occupies the pore spaces of the oil which also helps to improve productivity.

It is to be noted that, different types of mechanism can be observed in different oil field reservoirs. For an instance, the effect of the oil swelling and the carbon dioxide extraction of hydrocarbons enhanced the recovery of light crude oil. On the other hand in the recovery of heavy oil it is due to reduction of oil cause of dissolution of the carbon dioxide in the oil which improves the oil recovery (Abedini et al., 2014).

Advantages and limitations of CO_2 injection

Carbon dioxide injection enhanced oil recovery offers several advantages and those are listed below,

a) Injection of carbon dioxide helps to change the property of the crude oil which is favorable to improve the recovery of the oil by swelling of the crude oil, for example, Reduction in the viscosity of the oil, reduction in the surface tension between oil and water as carbon dioxide have tendency to dissolve in water, increasing oil density.
b) Carbon dioxide reduces the density of the water which reduces the density difference between the oil and water by reducing the gravity segregation.
c) The minimum miscible pressure require for carbon dioxide is low therefore carbon dioxide seems to be supercritical fluid at normal conditions in oil reservoirs when compared with other gases.
d) Carbon dioxide has capability to extracts heavier components up to C30.

Similar to any technologies, carbon dioxide enhanced oil recovery has few limitations as well and those are listed below,

a) High mobility of the carbon dioxide is the main concern as it reduces the sweep efficiency and early breakthrough of using carbon dioxide (Mathiassen, 2003).
b) The different causes of poor carbon dioxide enhanced oil recovery performances have been investigated by Robert Fergusson and Vello Kuuskraac. For an example, previously, volume of carbon dioxide used for injection was limited due to lower price of oil and higher price of carbon dioxide. Carbon dioxide flow in the reservoir was difficult to control therefore volume of carbon dioxide injected in the reservoir well was not enough to increase the productivity and achieve the optimized recovery of the oil. Gravity override phenomena, viscous fingering and channeling of the carbon dioxide lead to poor contact between the carbon dioxide injected which therefore reduces the sweep efficiency. Due to unexpected pressure decrease in a the reservoir and the very limited well operating pressure results the insufficient miscibility between the carbon dioxide and the crude oil in the reservoir. Other factors of poor performances in carbon dioxide oil recovery are the difficulty in injection due to high oil residue and poor management and control of carbon dioxide (Kuuskraa et al., 2010).

Some authors and experts have suggested the ways to reduce the adverse effects for an example to regulate the flow shutting can be introduced in the production well, also alternating water gas (WAG) can be applied, addition of foaming solution along with the carbon dioxide injection, installation of the well packers as well as application of the perforating techniques may improve and regulate the flow (Mathiassen, 2003). According to (Sohrabi et al., 2009) to solve the problem of the high mobility of the carbon dioxide, carbonated water or gravity stable fluid can be used during injection.

Miscible and immiscible CO_2 EOR

There are two main types of carbon dioxide enhanced oil recovery methods, one is miscible and other is immiscible carbon dioxide enhanced oil recovery process. These two processes are classified according to the phenomena that occurs after injecting the carbon dioxide in the reservoir well which whether the injected carbon dioxide is dissolved completely in the reservoir oil or not. Different factors are affecting this phenomena such as reservoir temperature, reservoir pressure, composition of the injected carbon dioxide as well as the oil components, all together decides whether the achieve process is immiscible or miscible after the injection of the carbon dioxide in to the oil reservoir. These two processes of carbon dioxide enhanced oil recovery and their mechanisms are different from each other and explained in following section (Haynes et. al, 1990).

Miscible CO2 enhanced oil recovery process: When the pressure of the reservoir is higher than minimum miscible pressure (MMP) then miscible carbon dioxide enhanced oil recovery occurs. Minimum miscible pressure is dependent on composition of the oil and the temperature of the reservoir. In this scenario, carbon dioxide can mix with the oil completely as it is super-critical. Due to complete mixing of carbon dioxide with the oil forms a single phase liquid. When carbon dioxide is injected in the oil reservoir and when it meets the oil it does not dissolve immediately. It needs multiple contact process in which light components within the oil vaporizes in to the phase of carbon dioxide. Along with this action carbon dioxide starts to dissolve in the reservoir oil. Once the process is speed up, carbon dioxide completely miscible in the reservoir oil. The miscible carbon dioxide forms a zone between the injected carbon dioxide and the original oil and the zone is known as miscible zone. The resulting mixture of carbon dioxide and oil has low interfacial force and low viscosity. In this way the oil recovery from the oil reservoir is improved due as oil became more mobile due to reduce viscosity. As the mobility of the carbon dioxide is higher therefore the injected carbon dioxide cannot be efficiently utilized. Therefore it is recommended that to increase the efficiency of this process, amount of carbon dioxide used ti be reduced and water should be injected along with the carbon dioxide. The process is known as water alternating gas (WAG) (Haynes et al., 1990; Tzimas et al., 2005). According to (Gozalpour et al., 2005) oil recovery in the miscible carbon dioxide enhanced oil recovery is promoted by lack of capillary effect. Schematic representation of the miscible carbon dioxide enhanced oil recovery process is shown in figure 5 b elow (Advanced Resources International, Inc., 2006).

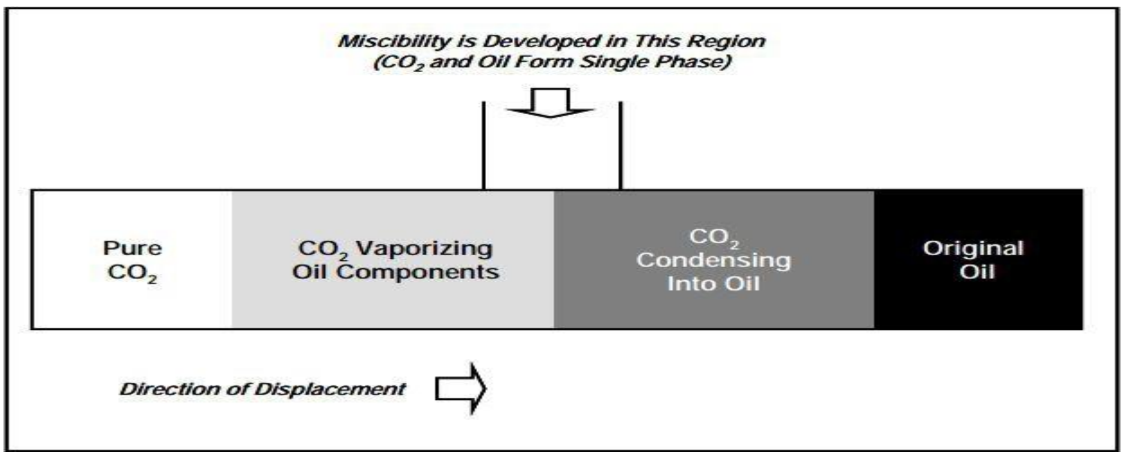


Figure 2: Miscible carbon dioxide enhanced oil recovery process (Advanced Resources International, Inc., 2006)

Immiscible CO2 enhanced oil recovery process: Now, when the reservoir pressure is below minimum miscible pressure, then the carbon dioxide does not dissolve completely in the oil. Here the part of carbon dioxide is dissolved in the reservoir oil whereas remaining carbon dioxide is in gaseous phase. This process is known as immiscible carbon dioxide enhanced oil recovery process due to partial mixing of carbon dioxide in the oil. The injected carbon dioxide enhanced oil swelling in the immiscible process due to saturation of the carbon dioxide in the oil. Viscosity of the mixture of carbon dioxide and oil is rescued.

Similar to the water flooding phenomena, injected carbon dioxide in this method improves the oil recovery from the reservoir by increasing the pressure as well as maintaining the pressure of the reservoir. In immiscible process, carbon dioxide is acting as an artificial gap cap which drives the reservoir oil towards the well or at the rim of the reservoir. Furthermore, carbon dioxide can removes the light oil components. The density of the oil is reduced after extraction of the light oil components which facilitate the reduction in viscosity and improves the oil recovery hence the productivity of the oil well.

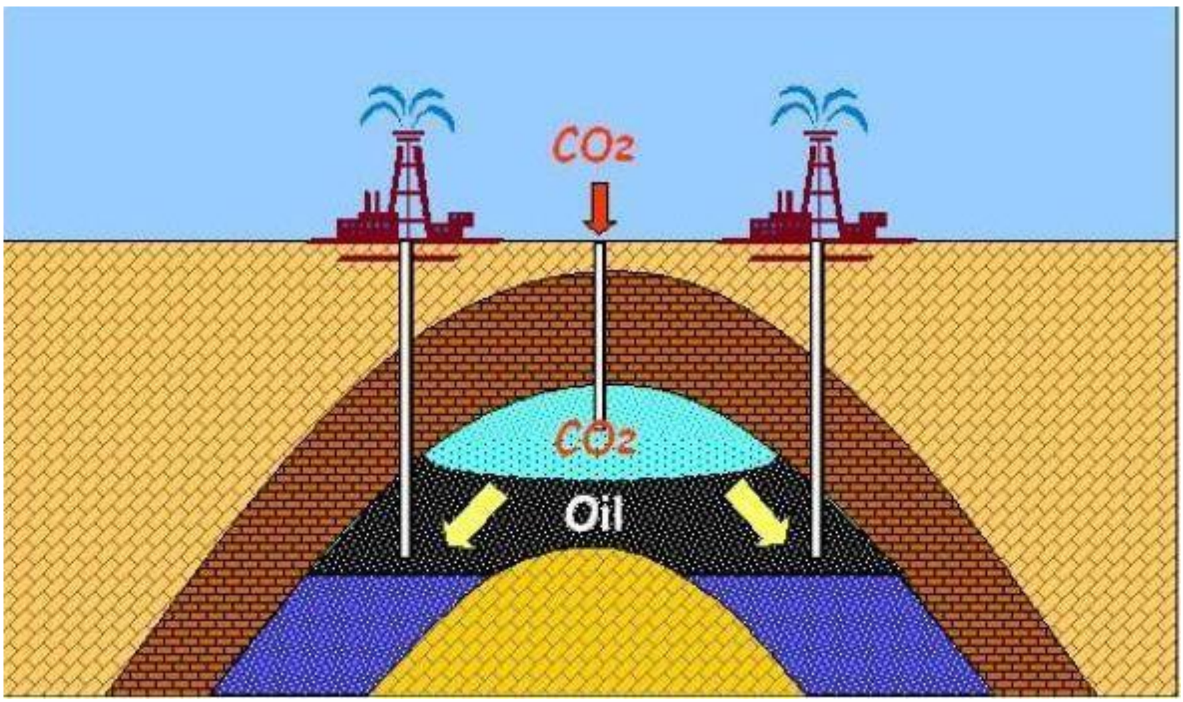


Figure 3: Immiscible carbon dioxide enhanced oil recovery process (Advanced Resources International, Inc, 2011; Tzimas et al., 2005)

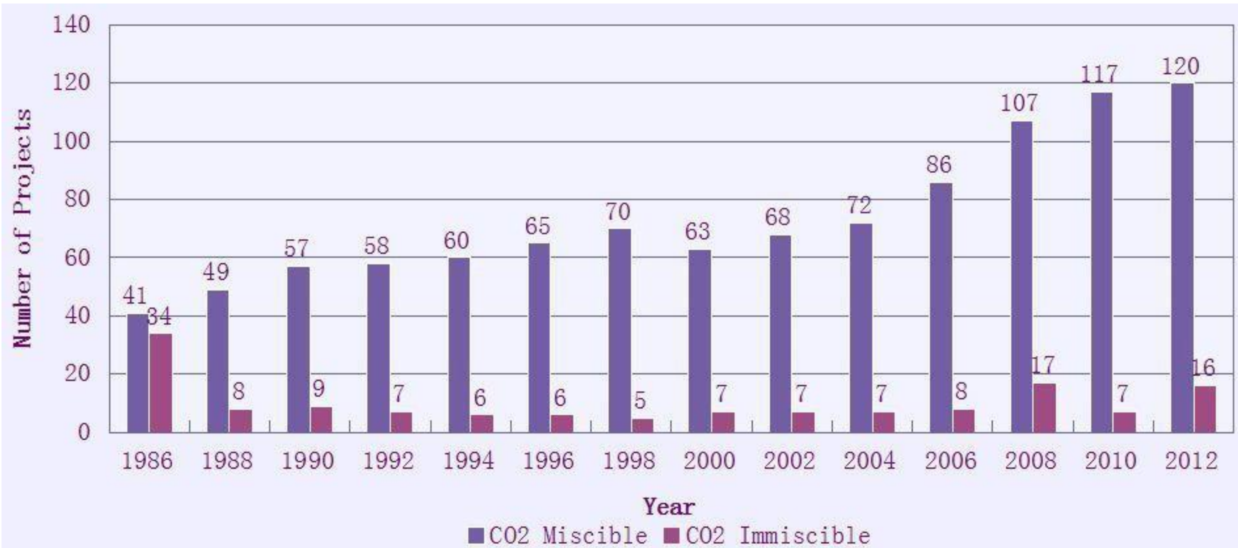
Normally, GSGI- gravity stable as injection is used to inject the carbon dioxide to the apex of the oil reservoir. Another option is using alternating gas for carbon dioxide injection for immiscible carbon dioxide enhanced oil recovery method. Schematic representation of the immiscible carbon dioxide enhanced oil recovery process is shown in the figure 6. (Advanced Resources International, Inc, 2011; Tzimas et. al, 2005).

When the density of the reservoir is too high then immiscible carbon dioxide enhanced oil recovery process is recommended, also when the oil in the reservoir is heavy then this method is recommended (Bagci, 2006). Table 5 below illustrates the comparison between the miscible as well as immiscible process. From the table it can be concluded that, the time required for the immiscible process project is longer as well as the scale of the project is larger when compared to miscible process projects. In terms potential, miscible process projects has less potential as compared to immiscible process. Immiscible projects can be carried out in the large scale also large scale of carbon dioxide storage can be carried out (Andrei et al., 2010).

Table 5: Comparison between carbon dioxide miscible and immiscible enhanced oil recovery process (Andrei et al., 2010)

	CO_2 Miscible	**CO_2 Immiscible**
Project Start	Before or after water flooding	After water flooding
Project duration	Short (<20 years)	Lon (> 10 years)
Project Scale	Small	Large
Oil production	Early (1- 3 years)	Late (> 5-8 years)
Oil recovery potential	Lower (4-12% OOIP)	Higher (up to 18% OOIP)
Recovery mechanism	Complex	Simple
Recycling of CO2 injected	Unavoidable	Avoidable
CO2 storage potential	Low (0.3 ton/ bbl)	Higher (up to 1 ton/ bbl)
Experience	Significant	Limited

Based on the data of the immiscible and miscible carbon dioxide enhanced oil recovery projects commissioned between the years 1986 to 2012 through global survey graph shown in figure 7 is plotted. From the figure, it can be derived that, the number of miscible projects are increasing with the entire range of years plotted whereas number of immiscible process projects have decreased in the year 2012 as compared to year 1986. From the figure it is obvious that popularity of the application of miscible process projects is more than that of immiscible process projects. Occidental Petroleum Corporation holds maximum numbers of carbon dioxide enhanced oil recovery projects (31 Nos) and is the company that holds largest number of miscible project in the world. The second largest company that holds maximum number of carbon dioxide enhanced oil recovery project is Debury Resources, the company holds 16 miscible process project and 6 immiscible process projects (Koottungal, L. 2012).



Graph 4: Installed miscible and immiscible carbon dioxide enhanced oil recovery projects from the year 1986 to 2012 (Koottungal, 2012)

Near miscible CO2 enhanced oil recovery process: (Zick, 1986) proposed a new mechanism which mainly combines the vaporizing gas and condensing gas in the year 1986. This was the year in which idea of near miscible process has occurred. This process of near miscible carbon dioxide enhanced oil recovery occurs when the temperature of the oil reservoir is slightly below the minimum miscible pressure. The main advantage of the process lies in the pressure requirement of the process; the pressure required for this process is lower as compared to miscible process. It helps to avoid the excessive cost required for the compression and makes the operation quite easier as well. Most of the miscible processes are the mixture of miscible as well as near miscible process. The reason of this is the reduction in reservoir pressure due to reservoir heterogeneity and the viscous fingering. One of the author (Shyeh-Yung, 1991) have listed different incentives for developing the process of near miscible, for an example, if one compares the efficiency of near miscible displacement with miscible then it can be found that both are nearly same.

Process of cyclic CO2 injection: The process of cyclic carbon dioxide injection is also known as carbon dioxide huff n puff process. This is one of the injection strategies developed to enhance the oil recovery by using carbon dioxide. The process of cyclic carbon dioxide injection is based on the process of cyclic steam injection which is usually applied in heavy oil reservoir since 1950s, later the method was also implemented for light oil all over the world (Alvarez et al., 2013).

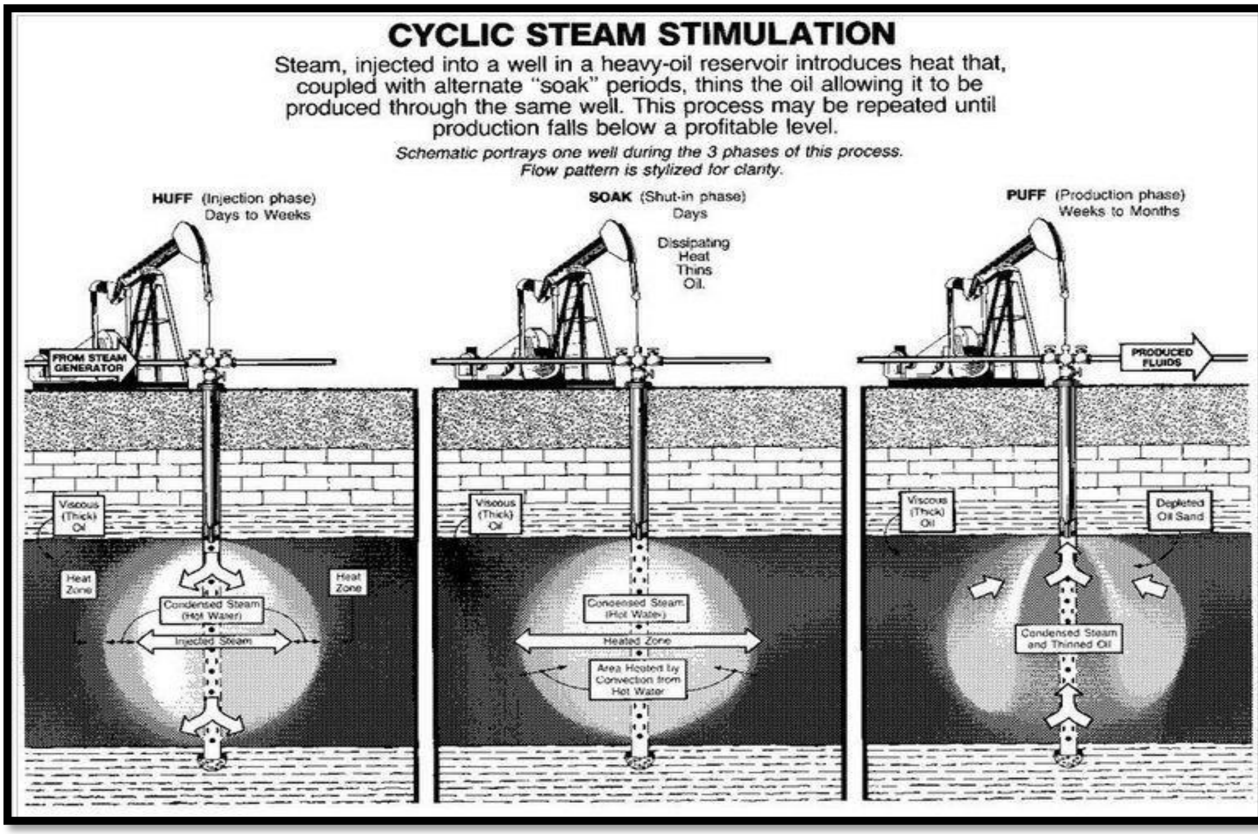


Figure 4: Cyclic carbon dioxide injection process (United States Department of Energy, 2010)

Figure 8 illustrate the entire process of the cyclic steam injection which pretty similar to the carbon dioxide huff n puff process. The process mainly consist of three different phases, injection phase also called as huff, shut in phase also called as soak and production phase also known as puff (Thomas et al., 1990). (Luo et. al, 2005) studied the combination of these injection methods and analyzed the cyclic carbon dioxide injection feasibility after cyclic steam injection. In the first phase which is huff, carbon dioxide is injected for some time in to the zone of oil which is a single well, once the carbon dioxide is injected in the well then the well is shut for the specific time period which is also referred as soaking period. Now, after end of soaking period, previous injection well becomes the production well known as puff. Production of oil is carried out through this well until the rate of production decreases to certain limit. This entire process is called as 'complete injection cycle'. This process of complete injection cycle is repeated for several time until the required amount of oil is extracted (Thomas et al., 1991).

The cyclic carbon dioxide injection mechanism is similar that of miscible process, such as oil swelling, viscosity of the oil decreases along with interfacial tension once the carbon dioxide dissolved in the oil, solution gas drive and extraction and vaporization of lighter oil components .(Abedini et. al, 2014). In addition to usual mechanism, permeability of the reservoir is increased due to carbonic acids and their corrosion effects which enhanced the dissolution of reservoir rock, carbonic acids are produced due to carbon dioxide and water (Wolcott et al., 1995). Relative permeability of the water as well as carbon dioxide reduces due to the hysteresis effect during production period. This results in increase of relative permeability of oil and hence the oil recovery of the oil reservoir is improved significantly (Menzie et al., 1963).

Several factors affect the performance of cyclic carbon dioxide injection process. Number of the studies shows the formation of gas cap, segregation, higher residual oil saturation. Loner soaking period as well as large carbon dioxide slug size may help the production of the oil in cyclic carbon dioxide injection process. (Torabi et al., 2010) carried out several experiments and the results of those experiments show those heterogeneous and fractured reservoirs are most suitable for cyclic carbon dioxide injection method. The reason of this being that the contact area of the oil in such kinds of reservoir is more therefore carbon dioxide can have more contact area with the oil. The study has revealed that if higher pressure is applied to the oil reservoir during the process of cyclic carbon dioxide injection process then the oil recovery is found to be improved.

As discussed earlier in this section the process of cyclic carbon dioxide injection process was designed for recovery of heavy crude oil, though this process can be implemented to recover the light oil as well. Risk in implementation of cyclic carbon dioxide injection method is a lot less as compared to the enhanced oil recovery methods (Monger et al., 1988).

New technologies in CO2 enhanced oil recovery: Potential approaches to optimize carbon dioxide enhanced oil recovery along with storage has been studied by Advanced Resources International Inc. for example next generation carbon dioxide enhanced oil recovery technologies such as application of the carbon dioxide enhanced oil recovery to the residual oil zone which are immobile, applying carbon dioxide injection earlier to the reservoir and many more. Different changes have occurred over the period since the technology of carbon dioxide enhanced oil recovery have introduced such as amount of carbon dioxide injection is increased, combining the carbon dioxide with water or gas and several other methods. Also there are several methods that have emerged in advanced well drilling and strategies of completion. Due to these continuous changes the technology of carbon dioxide enhanced oil recovery has improves to 'state of the art' technology and eventually the efficiency of oil recovery has improved. Still there are some problems that have been faced by this 'state of the art' technology which can be solved probably by employing 'next generation' carbon dioxide enhanced oil recovery technology. There are mainly four stages in this 'next generation' carbon dioxide enhanced oil recovery technology.

a) Introducing more carbon dioxide in to the oil reservoir
b) Design of the well and placement of the well along with the infill well should be optimized. This is necessary to increase the contact between the oil and the carbon dioxide which is injected in the reservoir.
c) Measures to improve the mobility ration between carbon dioxide or water and the oil. It is necessary to extend the miscibility range which is required to reach higher oil recovery efficiency.

The study was conducted by Vello Kuuskraa and Robert Ferguson, the study shows that the 'next generation' technology has capability to improve considerably the carbon dioxide enhanced oil recovery as well as storage of carbon dioxide if applied. Three major benefits of this ‘next generation’ technology for carbon dioxide enhanced oil recovery is summarized in this study and those are,

a) Implementation of next generation carbon dioxide enhanced oil recovery increases the oil production by almost 40% as compared to the current techniques being used in the field of carbon dioxide enhanced oil recovery.
b) Employing the next generation carbon dioxide enhanced oil recovery technology might create huge demand for sources of carbon dioxide, prediction is around 9 to 13 Giga-tons
c) Captured carbon dioxide which is used to inject in the oil reservoir is carbon free up to 50% to 80% with the application of next generation of carbon dioxide. Enhanced oil recovery (Kuuskraa et al., 2010).

Chapter 3: Case Study

Introduction

Kelly Snyder is a massive oil producing area situated on the eastern edge of the Permian Basin within western Scurry County. The oil field Kelly Snyder was discovered in the year 1948. It is one of the major oil producing reservoir in the United States with approximately 2 ¾ billion bbl oil in place originally. Kelly Snyder draws oil from 6700 foot solution gas driven reservoir known as the Canyon Reef formation which is situated in the Horseshoe Atoll. Horseshoe Atoll is one of the largest subsurface limestone reef dunes in the world. After the drilling the Atoll is found to be 175 miles long which is stretched below western Scurry and Western Kent counties which then turn south under the counties Howard and Borden further moves northeast across the subsurface of Terry, Lynn, Gaines, Martin and Dawson counties. There are several fields in the Canyon Reef formation in the Atoll which produce the oil but Kelly Snyder is the most productive. The cumulative production of the Kelly Snyder oil field at the beginning of the year 1993 was 1227626890 barrels of oil. It is to be noted that the exploration of the oil around the Canyon Reef began in the 1920s when independent prospector showed interest and started drilling within the area but they found only negligible production of oil (Craft, B., Hawkins, M. & R. Terry 1991). As mentioned earlier the primary production mechanism for oil extraction was solution gas driven and the recovery of the gas results in less than 20 percent of the oil in place originally. In the year 1953, the SACROC unit was formed and enormous pressure maintenance program was started in September 1954. Kelly Snyder has center line row of wells which is located along the reservoir's longitudinal axis through which water was injected. The maintenance program along with production control under combined operations has effectively restored a huge volume of the reservoir liquid saturated condition, bottom-hole pressure was effectively rebuilt and it stabilized the production of GOR at near solution levels. Overall performance of the water injection program along with technical capability was very inspiring, although technical team of the major shareholder company were continuously examining the potential ways to improve critical oil recovery which was expected from the program involving water injection. On 26th January 1972, one of the largest oil field in United States, SACROC initiated a huge CO_2 carbon dioxide project. The miscible flood CO_2 EOR project undertaken by the company was one of the largest secondary oil recovery projects of this type. The estimated oil recovery of this project was 230 million barrels of oil, which was additional. This magnitude of oil was not discovered in the USA for ten years then only the significance of this increase in oil reserves may be realized, exception to this was Alaska. The location of SACROC unit is near town of Snyder which is in Scurry County located in West Texas. The Figure 9 below shows the location of the SACROC unit. The unit has 50,000 acres of area which covers 98% of the Kelly Snyder field and it is mainly combined with other 4 units in 35 × 5 miles Canyon Reef formation. As stated earlier the field was discovered in 1948 and approximately 2000 wells had been drilled by 1951.

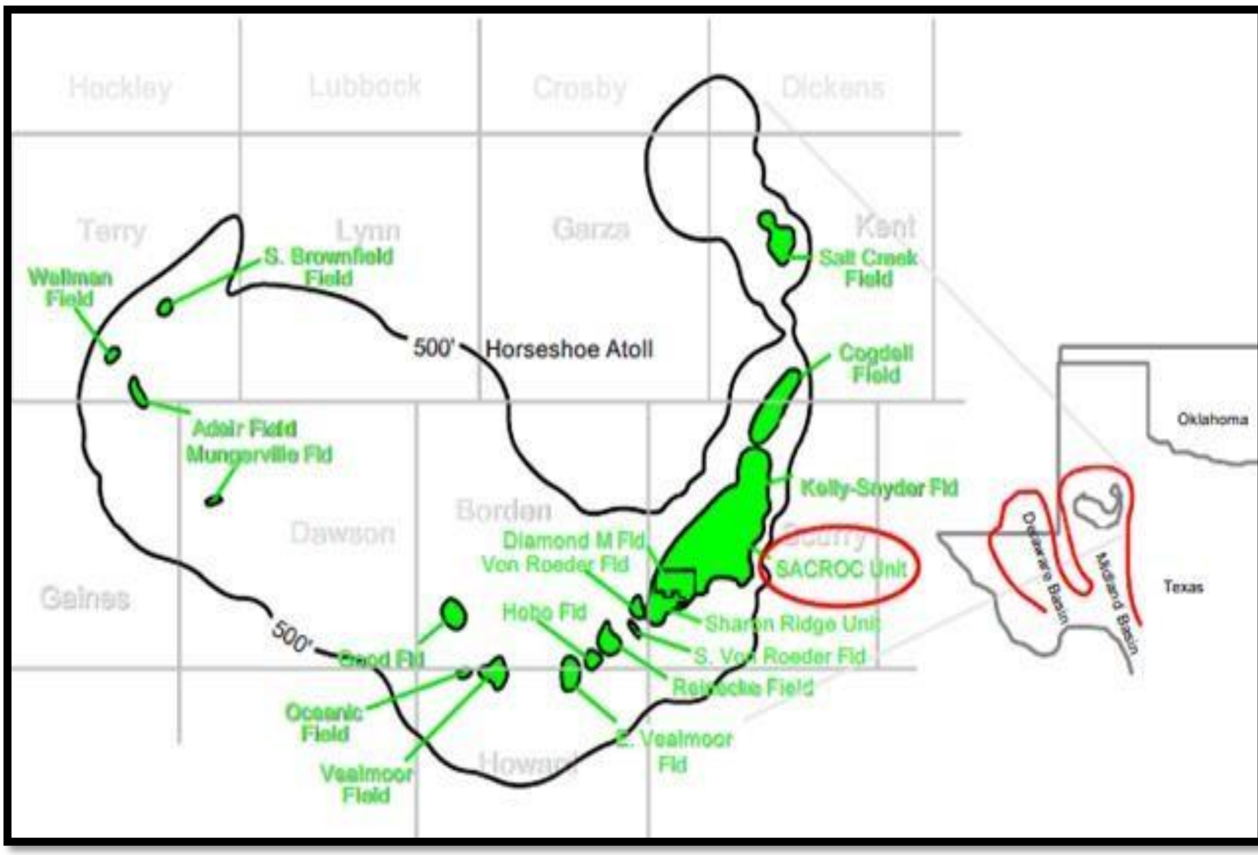


Figure 5: Location of Kelly Snyder Field

Reservoir geology

The Kelly Snyder oil field is located in West Texas, in County Scurry which is the major combined oil field among the four adjoining fields along 35 × 5 miles Canyon Reef formation. The Canyon Reef formation comprises of Pennsylvanian age limestone which happens to be 6700 feet deep. The huge reef builds up with gently sloping and thinner flanks in northeast and southwest direction. The thickness of formation differs from average 800 feet on the crest of the reef to nearly less than 50 feet on the flanks with an overall average of 213 feet. As stated in earlier section, the SACROC unit consists of 98% of the Kelly Snyder oil field with total numbers of the wells are 1256 within 50000 acres. The combined reservoir is largely restricted by porosity development on the east and west whereas by offsetting units on the southwest and northwest. Oil and water contact is poorly defined in some of the areas but the effective contact occurs in most of the areas. During pressure depletion very limited water influx were detected which indicate considerably smaller aquifer in the adjacent areas. The original BHP of the reservoir oil was under the saturated condition is 3122 psig, the solution gas content of the reservoir is a little under 1000 scf/ STB whereas the bubble point pressure is 1805 psig. The seal trap which is covering on the productive zone is the Triassic age Dockum formation, the Paleocene/Eocene Ogallala Formation and the Permian-age strata.

Figure 10 and 11 shows the stratigraphic column of the Permian Basin and Canyon/ Cisco formation respectively.

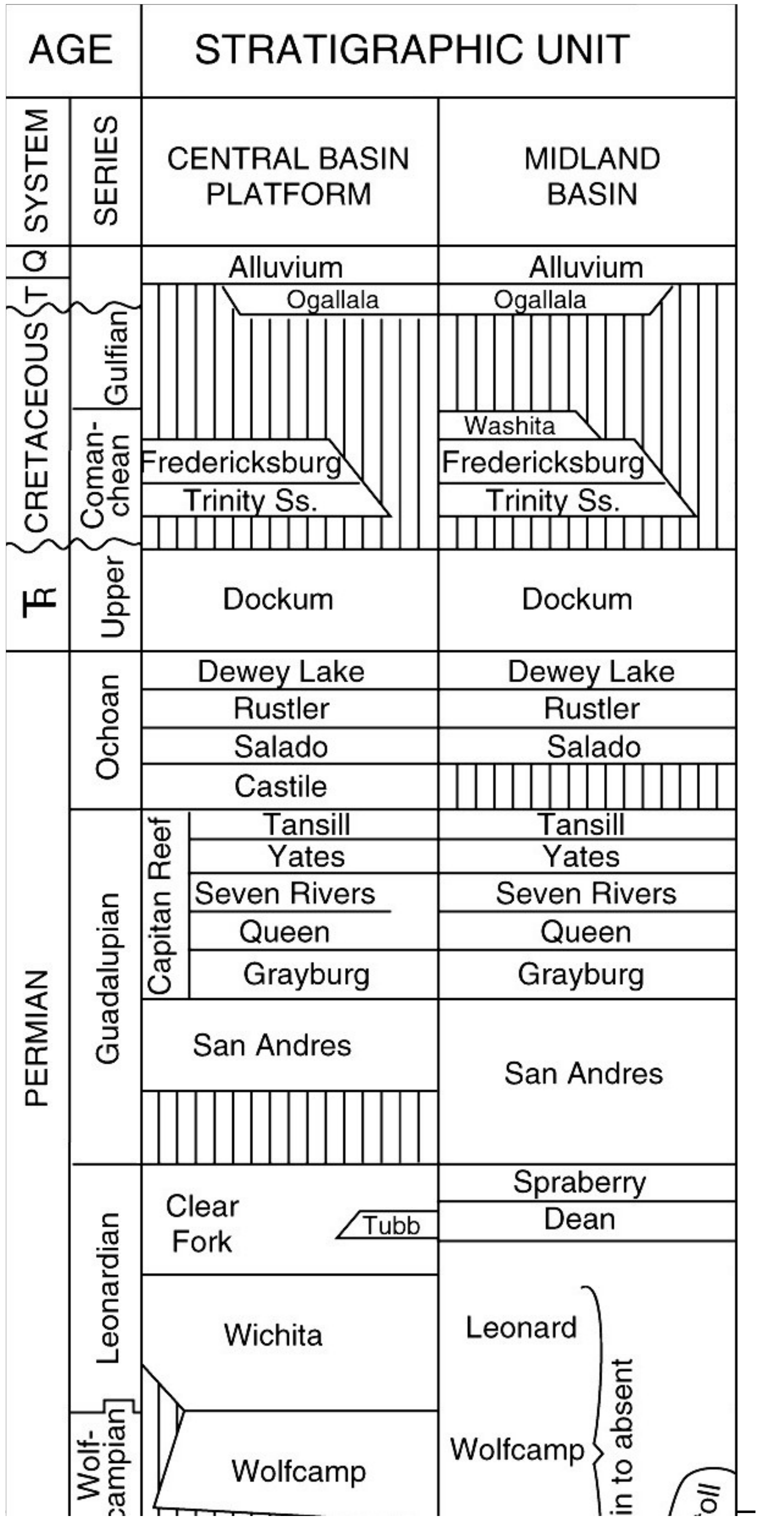


Figure 6: Stratigraphic Column of the Permian Basin,

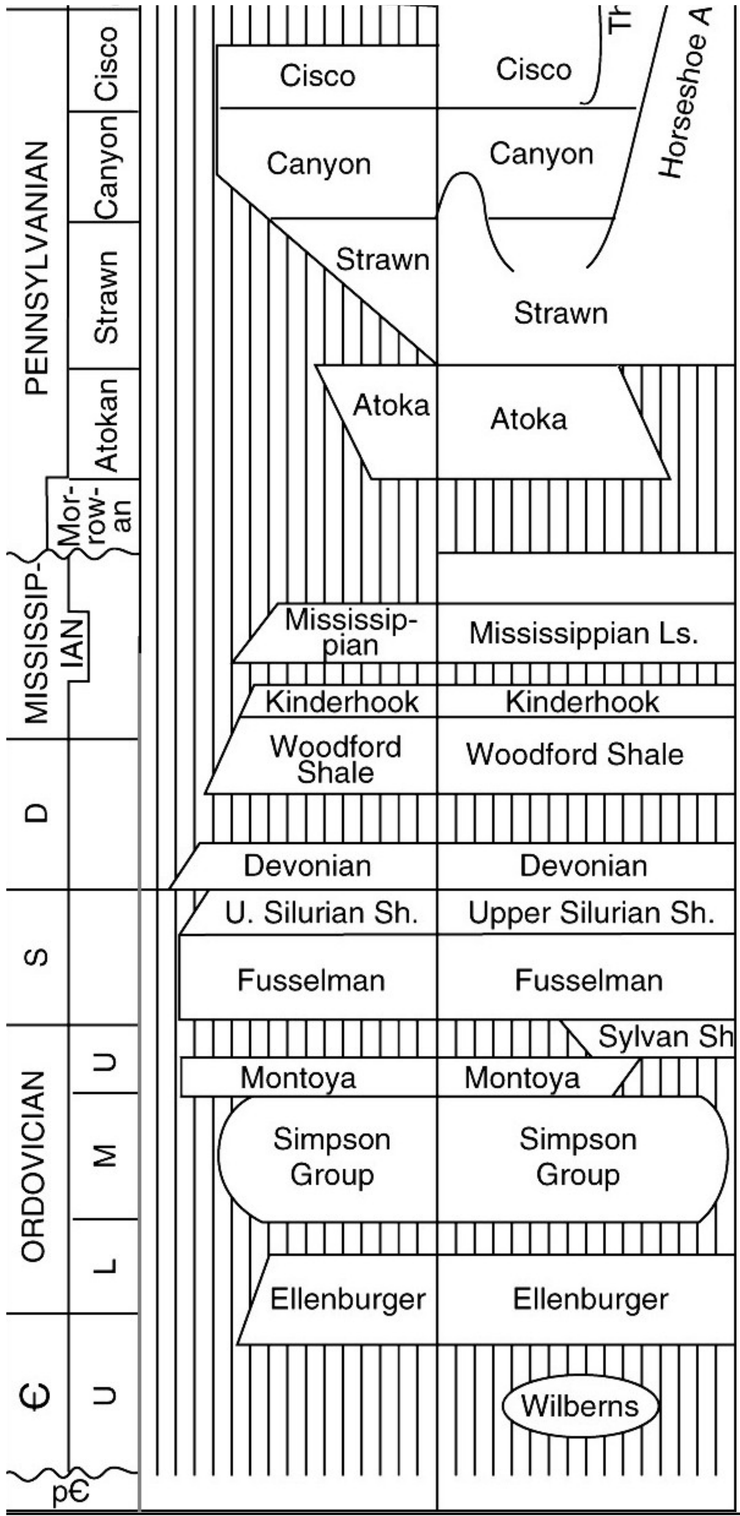


Figure 7: Stratigraphic Column of the Canyon/Cisco Formations

Reservoir parameters

The reservoir properties of Kelly Snyder is comparatively favorable. The approximate depth of reservoir is 6700 feet whereas contact of air and water can be discovered at 4500 feet. Average porosity of reservoir is around 7.6 % which ranges from 4 to 20 %. Reservoir temperature below 4300 feet is 130 F whereas initial reservoir pressure was 3122 psig. The number of wells drilled in the Kelly Snyder reservoir are 1256. The summary of reservoir data is shown in table 6 below ((Dicharry, Roy M., T.L. Perryman, and J.D. Ronquill, 1973)

Table 6: Basic Reservoir data of the Kelly Snyder oil field (Dicharry, Roy M., T.L. Perryman, and J.D. Ronquill, 1973)

Physical Features of Reservoir	
Approximate depth	6700 ft
Approximate water/oil contact (subsea),	below 4500 ft
Average gross thickness,	213 ft
Properties of Reservoir Rock (Gross Reef)	
Average porosity,	7.60%
Average permeability	19.4 md
Average interstitial water saturation,	36 percent pore space
Average residual oil saturation,	26 percent pore space
Reservoir Temperature (–4,300 ft),	130 F
Initial Reservoir Pressure (–4,300 ft),	3122 psig
Water Injection Commenced	21-Sep-54
Unit MER (Aug. 1972), B/D	243978
Unit Surface Area, acres	49900
Total Wells in Unit	1256
Unit Hydrocarbon Pore Volume	
Acre-ft	517434
Barrels	4014253000
Approximate Gross Acre ft in Unit	10668000
Original Stock-Tank Oil in Place	2727000000

Fluids parameters

The oil in reservoir was under saturated condition initially where original BHP was 3122 psig. Solution gas content of the oil was marginally under 1000 scf STB and bubble point pressure was around 1805 psig. The oil in Kelly Snyder reservoir is high in intermediates, for example, C_2 to C_4 up to 31.5 mol %. The surface product separation conditions are very sensitive between stock tank oil and casinghead gas. Table 7 and 8 below illustrate average reservoir fluid composition as well as properties and flash separation data respectively (Dicharry, Roy M., T.L. Perryman, and J.D. Ronquill, 1973).

Table 7: Fluid Parameters (Dicharry, Roy M., T.L. Perryman, and J.D. Ronquill, 1973)

Reservoir fluid composition	
Component	**Mol (%)**
Co_2	0.32
N_2	0.83
C_l	28.65
C_2	11.29
C_3	12.39
i-C_4	1.36
n-C_4	6.46
i-C_5	1.98
n-C_5	2.51
C_6	4.06
C_7	30.15
Total	**10000**

Molecular Weight of C7 = 197.4

Specific Gravity of C7 = 0.841

Bubble-Point Pressure (at 130” F), =1,820 Psia

Reservoir Fluid Viscosity at 1,820 psia and 130^0 F, CP 0.38

Reservoir Fluid Density-at 1,820 psia and130^0 F, lb/cu ft is 41.8

Table 8: Flash separation data (Dicharry, Roy M., T.L. Perryman, and J.D. Ronquill, 1973)

	25 psia and 95 F	**31 psia and 75F**
Solution GOR, scf/STB	990	910
Stock-tank oil gravity, ^{0}API	41	42.7
Casinghead gas gravity	1.087	1.03
FVF at 3,137 psia, bbl/STB	1.528	1.472
FVF at 1,820 psia, bbl/STB	1.557	1.5

Oil in place

The Kelly Snyder oil field which falls within the massive SACROC unit had 2.73 billion STB estimated oil in place originally. The cumulative production accounted to 536 million STB through the year 1971 which is approximately 19.7 % of the oil originally in place. The analysis of this early production shows that the mechanism in primary reservoir was driven by solution gas and no water drive was existed during the early production. The GOR's increased in the first 5 years as the production was less than 5 % of the oil in place initially which resulted in 50 % reduction in average pressure of the reservoir to 1560 psi. It was therefore necessary to implement some type of pressure maintenance to avoid low oil recovery from the reservoir. The total production through mechanism of solution gas drive shows the final recovery of the oil up to 19 % of the oil in place originally. The oil recovery through injection was only 15 % (Reeves, S. 2008).

Initial distribution system of CO_2- WAG in Kelly Snyder

Since the reservoir was discovered, the development process was consequently rapid and the process was completed by 1951. The total wells drilled within 3 years of span were 1671. Figure in appendix VI shows the injection as well as production history of the field Kelly-Snyder. In September 1954, water injection was started using 72 center line injectors with unique pattern. Additional injection capacity was added in the beginning of 1969 to provide increasing oil demand. 72 additional wells were converted in to injection services between the years 1969-71. Therefore total number of centerline injectors are increased to 144. All the injectors are in operating condition currently. Total 771 million bbl water was injected by the end of 1971. The reservoir was stored to liquid saturation condition and therefore it was producing GOR which was stabilized at a near solution ratio. Figure in appendix VII. Shows the position of centerline injection well along with pattern injection which is CO_2 injection. It is necessary to note that, center line injection has lost its identity due to pattern injection. The centerline project was very satisfactory as it gives ultimate recovery by using method of water-flooding, however more than 1 billion bbl oil was projected to remain undiscovered at the end of the phase. Therefore in the year 1968, the technical planning committee has selected the process of CO_2 EOR after evaluation to improve the recovery of the field (Kane. A, 1979).

In the pattern area injection well, dual water and CO_2 injection lines were commissioned. Centrifugal pumps were used for 4 stations of high pressure water injection solution at pressure of 2000 psi whereas CRC boosters were used to supply CO_2 which is located in phase 1. Reinjection station is located in phase 2 (Kane. A, 1979). Major owners of the SACROC formed Canyon Reed Carriers Inc. which is known as CRC in the year 1970. The main aim behind the formation was to deliver CO_2 to the distribution unit from Val Verde Basin which was located around 200 miles in the south. The CO_2 was produced as a byproduct in the several gas plant. A delivery system was commissioned in the year of 1971 comprises of 40 mile and 180 miles long transmission pipeline with 12 inch and 16 inch diameter. Four compressor stations were installed in Val Verde Basin along with the single booster station on the pipeline and another at SACROC. Figure in appendix VII shows the location of the stated system. This system was designed in such a way that it delivers 220 MMcf/d to SACROC and 20 MMcf/d to another unit in North Crossett (Kane. A, 1979).

Presently number of producing wells in the Kelly-Snyder oil field which use CO_2 EOR are 300 and number of injector well are 300 (Advanced Resources International, Inc. 2006).

Recoverable reserves

As discussed in earlier section, the initial mechanism for production was solution gas driven and the production was as low as 20 % of the original oil in place. The relatively low recovery factor due to nature of the reservoir was highly heterogeneous and the network of open fracture. Table 8 shows the recoverable data of Kelly Snyder oil field, whereas table 9 shows the known recoverable oil in 2004, estimated oil in place which is original and the estimated recovery efficiency (USGS, 2012).

Table 9: Recoverable data (USGS, 2012)

OOIP (MMSTB)	2700
Recoverable reserves (MMSTB)	533
Recovery Factor (%)	20

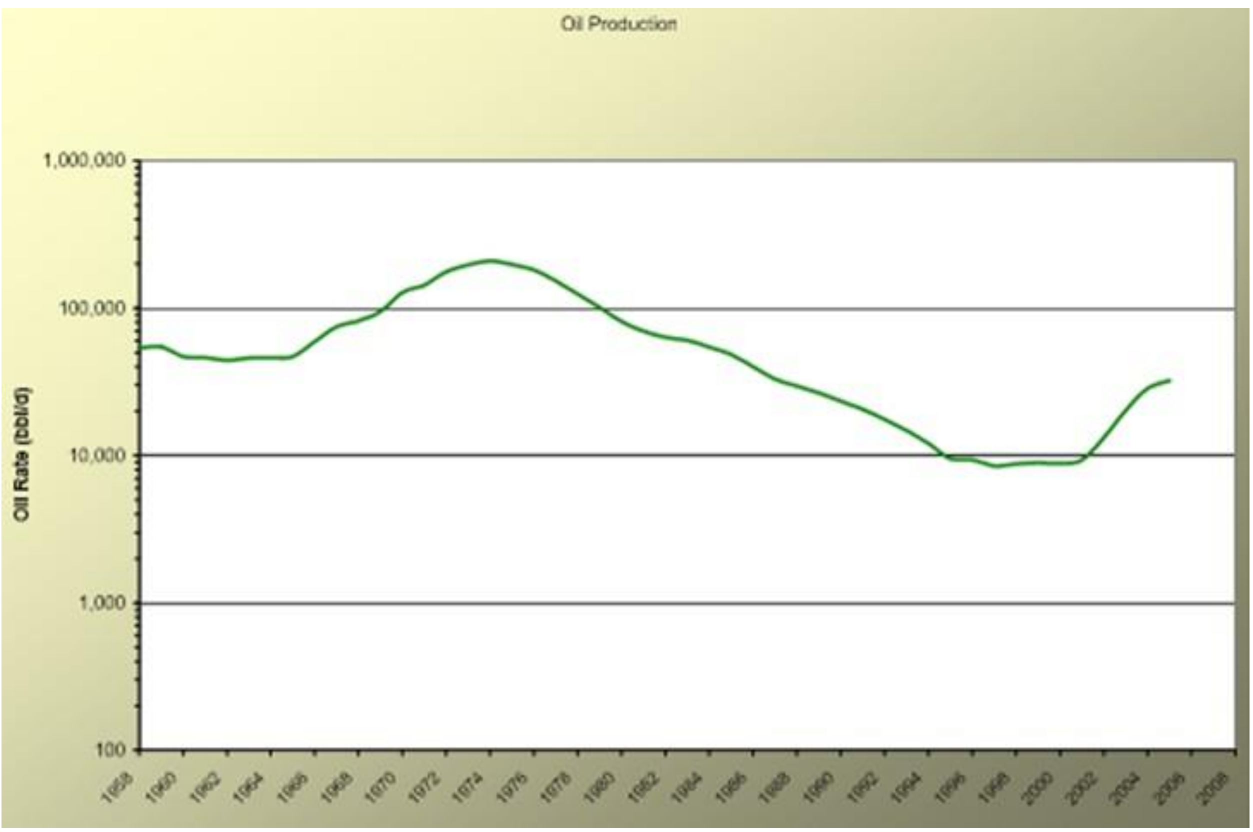
Table 10: Recoverable data and efficiency of SACROC (USGS, 2012)

Field	**Components**	**Known recoverable oil (2004) (MMBO)**	**Estimated original oil in place (MMBO)**			**Estimated recovery efficiency (%)**		
			min	median	max	min	Median	Max
Scurry (SACROC)	Kelly-Snyder, Diamond-M, North Snyder	1,735	3,000	3,100	3,300	55	62	65

The known recoverable reserves at the beginning of year 2004 was 1735 million barrels of oil whereas average estimated original oil in place was 3100 million barrels of oil with minimum estimated oil in place of 3000 million barrels of oil and maximum estimated oil was 3300 million barrels of oil. Average estimated recovery for SACROC unit was 62 % (USGS, 2012).

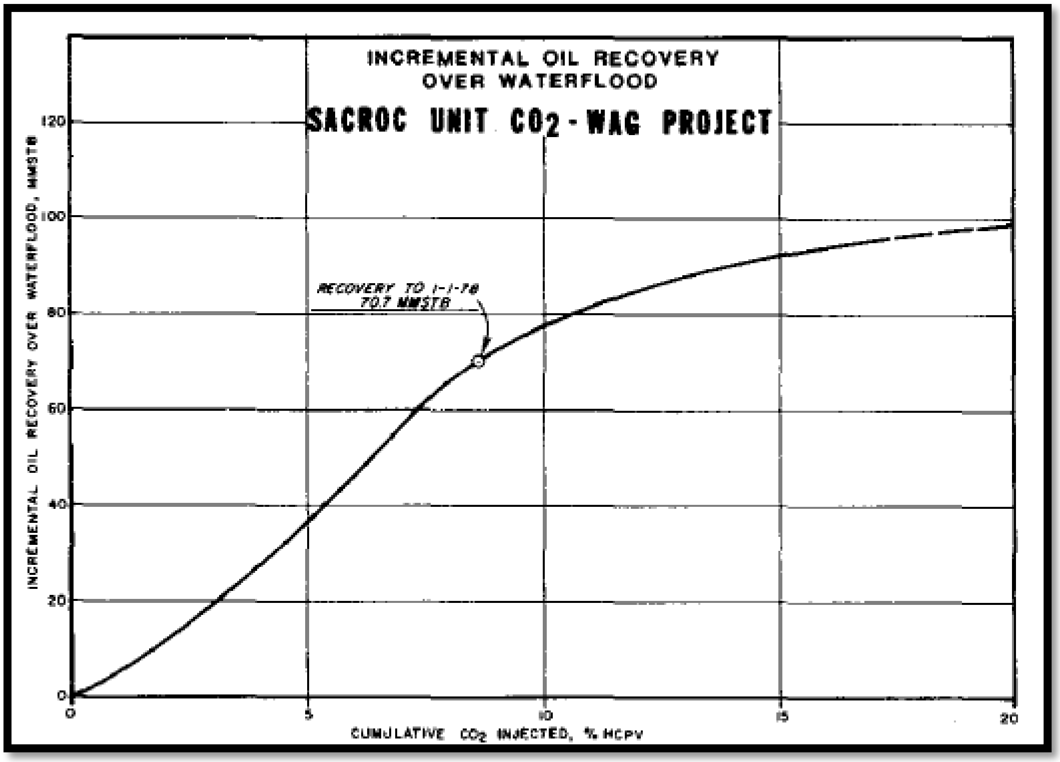
Oil production profile

The primary aim to form SACROC unit was to facilitate water flooding operations in the field and it was formed in the year 1952. Actual operations of the SACROC unit began in 1954. Carbon dioxide EOR started in the year 1972. Initially unit used anthropogenic carbon dioxide and presently it has focused in the central plain primarily. In central plain the architecture of reservoir is illustrative of horizontal installation and responsive to pattern flooding. The critical milestone of these operations were observed in the decade of 1990’s. The production of the unit dropped which was greater than 20 % per year. The peak was 210000 barrels per day in the 1970’s which dropped to almost 9000 barrels oil per day in the year 1995. The unit was considered to be mature and considerably depleted in the mid 1990's. The situation was such that owners of the field were seriously thinking to abandon the field as the estimated economic limit was approaching quickly. On the other hand some of the owners were focused on implementing long term plan to capture the production decline, reduce expenditure as well as to restore economic feasibility of the oil producing unit rather than facing the viewing abandonment liability as well as negative cash flow. The efforts had been put to increase production via aggressive CO_2 injection since the year 2000. This efforts tripled the production, the efforts had been put to reduce the cost and implement the better pattern of management. The figure 11 shows the pattern of oil production since 1958 till 2008. It can be clearly observe that the production has reached its peak in between the year 1970 to 1978 and it rapidly dropped till year 2000. Since implementing aggressive CO_2 injection has improved the capturing of the oil (Reeves, S. 2008).



Graph 5: SACROC unit production since the discovery (Reeves, S. 2008)

Production forecast of CO_2 –WAG project in Kelly-Snyder (SACROC) and its comparison with combination of center line- pattern area water flood,



Graph 6: Incremental oil recovery

The performance of CO_2 WAG project predicted by reservoir engineering committee as below,

1. Basic curves have been developed by the committee which relates to injected fluid cuts and injected cumulative hydrocarbon pore volume. This curve is for an average pattern for both water as well as CO_2 shown in graphs in appendix XIV
2. Individual pattern prediction model have been used by committee to evaluate the production schedule of water, oil, gas and CO_2 in each 9 spot pattern. To calculate individual pattern performance, this method uses the typical average pattern water/ CO_2 cut curves as well pattern hydrocarbon pore volume and a schedule of predicted individual performance of pattern. The oil production calculated from this method is a direct function of water cut and CO_2 curves used.
3. For center line area, schedule were developed for oil, gas and water which is based on decline trends of extrapolation.

4. Unit performance was obtained by summing the center line schedule and individual pattern.

Using above method, total unit performance was predicted for two system CO_2 WAG and combination of center line- pattern area water flood. It has been discovered by the committee that the incremental oil recovery by the CO_2 WAG would be 107 million STB over water-flooding which is equivalent to 8.1% of the initial oil in place in the area of patterns. The earlier estimated value is greater than the 107 due to difference in recovery calculated by simulator as well as low estimation of oil in place 614 million STB which was calculated by the study using black oil simulator. It was clear by early 1976 that the performance of the project is different than the one predicted in the year 1973 by the committee. Therefore by using modified CO_2 and water cut curves new predictions were made which shows actual performance of the cut from pattern area corresponds to phase 1 and accounted the different areas of the field and their cut performances for example flank areas or area adjacent to the center line of the field. By extrapolating from the initial point, the "reviewed" curve for water curve was obtained in the year 1976, the basis of the review was compositional simulator curve. Based on this curve water production in the year 1976 was calculated along with pattern area performance forecast. The curve obtained from the compositional model and its comparison with actual water cut curve is shown in appendix IX. This curve shows water cut vs hydrocarbon pore volume injected for the pattern areas in phase 1 in October 1976. The actual water cut curves shows poor recovery, the reason behind this is collective effects of centerline water flood invasion in the area of pattern as well as higher level of reservoir heterogeneity. On the other hand higher level of heterogeneity and initial free gas saturation local effect results in poor recovery in actual CO_2 performance curve (Hull, P. 1970) (Dicharry et al., 1973)

The pattern areas are separated in to 9 distinct "type areas" that dependent on the location corresponds to the flank areas or the center line. The reason being the difference in geology as well as location of the pattern affected by the centerline water-flood which was used at the time of pattern injection. Figure (B) in appendix IX shows the revised water cut curve whereas figure (A) in Appendix IX shows CO_2 cut curve by compositional model. Values were entered in the individual pattern prediction model for every group, then by using actual injection data prediction was run. Additional runs were performed in the CO_2 and water cut curve after suitable shift in of the curves until the satisfactory match between the actual cut performance and calculated cut performance was obtained. For each area type this process gives similar set of water as well as CO_2 cut curves. The performance of the field is then predicted as explained in above, note that cut curve set is used by the each pattern obtained during the process of matching for the area type where it fit. In the year 1976 this system was used to predict the performance in future for few CO_2 slug limits on a specific pattern from the range of 8% HCPV to 20% HCPV.

Now, comparing both these cases for the economics then it can be found that continuing CO_2 injection past 12% HCPV would affect the satisfactory economics. Considering this analysis the slug limit of CO_2 was reduced to 12% HCPV. This limit of 12% was carried out in the year 1977. The reason being the considerable changes in predicted rate of injection from those carried out in the forecast in 1976, therefore revised forecast was carried out in the year 1977 by using the same process essentially used in the year 1976. Graph 6 shows the incremental oil recovery curve for the historical and predicted oil recovery forecast. The curve in graph 6 shows at cumulative injection more than about 9% HCPV, efficiency of the CO_2 process decreases quickly. Profitability at higher size of CO_2 slugs resulted in reduced efficiency of the overall CO_2 process with greater level of collective CO_2 injected. Graph (C) in appendix IX shows addition requirement of CO_2 injection as well as added CO_2 production per STB of excess oil which is the cumulative function of CO_2 slug limit. The graph (D) illustrated in appendix IX shows the rapid increase in requirement of CO_2 injected and the produced CO_2 / barrel of excess oil with the increased slug limit of CO_2. Incremental operating cost increases rapidly with the loss in efficiency of the process and subsequently reduce the profitability at higher slug limit of CO_2. For individual pattern CO_2 slug from 8% HCPV to 20% HCPV and for continued CO_2 injection, and for the limiting injection the economics were forecasted (Kane. A, 1979).

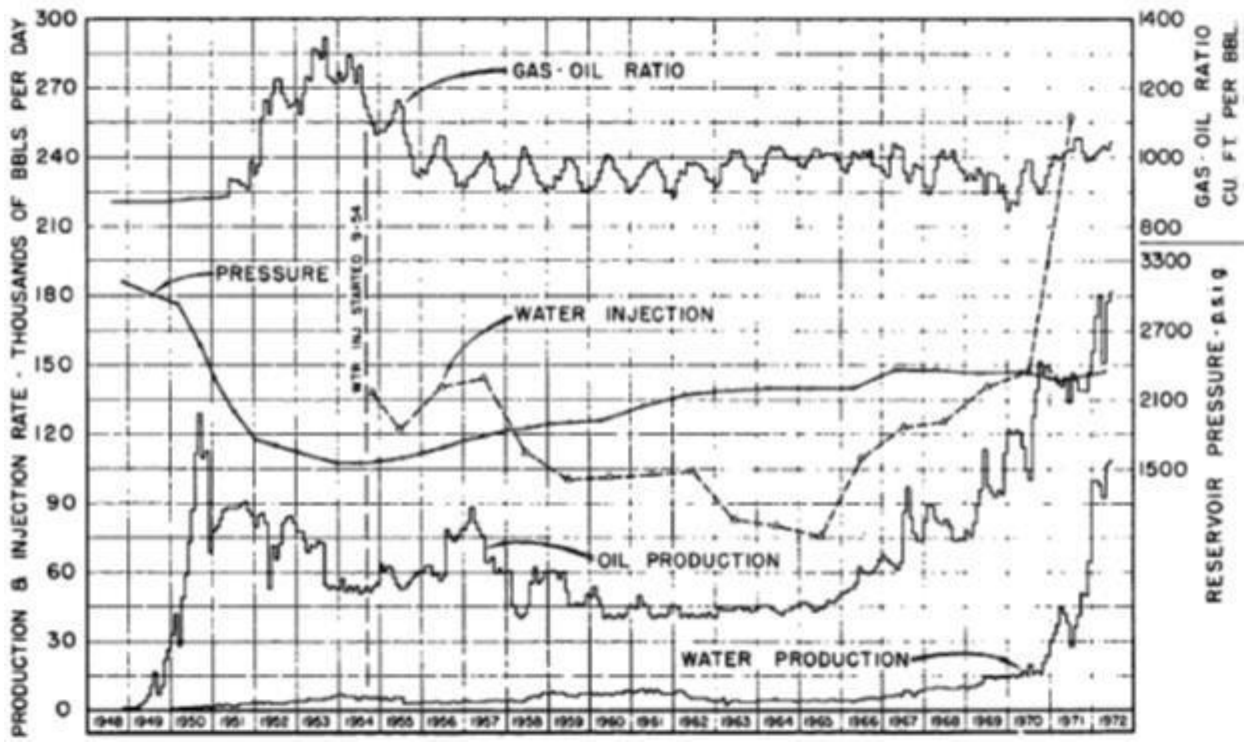
Table 11: Comparison of production forecast (Kane. A, 1979)

Parameters	Continue injection to 12% HCPV CO2	Curtail CO2 injection on 1-1-1978	Combination of centerline/nine spot water-flood
Cumulative oil production (1-1-78), MMSTB	937	937	866
Oil reserves (1-1-78), MMSTB	238	224	221
Ultimate recovery, MMSTB	1175	1161	1087
Ultimate recovery, % original oil in place	55.6	55	51.4
Incremental recovery over water-flood, MMSTB	88	74	-
Incremental recovery over water-flood			
Total field basis, % original oil in place	4.2	3.6	-
Pattern area basis, % original oil in place	6.7	5.7	-
Cumulative CO2 injected (1-1-78), Bcf	344	344	-
Future CO2 injection (1-1-78), Bcf	192	44	-
Ultimate CO2 injected, Bcf	636	388	-
Ultimate CO2 injected, % HCPV	13.4	9.7	-
Ratio of ultimate CO2 injected to incremental oil recovered, Mcf/STB	6.1	5.3	-
Cumulative CO2 produced (1-1-78), Bcf	53	53	-
Future CO2 production (1-1-78), Bet	73	44	-
Ultimate CO2 production, Bcf	126	97	-

Table 11 shows the predicted recovery and the injection data for the two cases along with center line/ nine spot pattern area water flood. Incremental recovery of 88 million STB over water flood indicated by 12% slug limit case which is almost same to 6.7% of the initial oil in place within the pattern area. In 1973, reservoir engineer study group estimated 107 million STB which is more than 88 million STB. The reduction in estimation of oil recovery is due to considerable reduction in limit of CO2 slug from HCPV 20% to 12% and second reason being the higher operating cost as well as considerable investment which reduced the economic life which was more than anticipated initially (Kane. A, 1979).

CO_2 Injection strategy

Carbon dioxide EOR has been practiced since more than 30 years in the oil and gas field. The design as well as operation of the carbon dioxide EOR is always dependent on the price of the oil. It has been always observed that when the price of oil is low then the efforts are made to maintaining the revenue through minimizing the cost. For gravity stable injection design coordinating project finances as well as recovery efficiency is a challenge. The method suggested by (Zhou et al) shows if the reservoir contains the high permeability vertical channels that may cause the carbon dioxide flow rates in the reservoir to be comparatively higher as compared to critical gravity stable flow rate which results in recycling of the gas. (Zhou et al) have proposed the WAG design which is tapered to enhance the recovery efficiency and the operational flexibility in the depleted field.



Graph 7: Performance history and injection strategy (Dicharry, Roy M., T.L. Perryman, and J.D. Ronquill, 1973)

Original plan: Preliminary project design was developed by a committee aiming to inject continuous 20% HCPV- hydrocarbon pore volume slug of CO_2 which was followed by water injection into 174 inverted 9 spot pattern which was located ahead of the center line leading edge. This plan was changed to following after laboratory and technical studies,

1. The area was expanded to additional 28 9 spot pattern along the leading edge of centerline as well as slightly behind the leading edge of water-flood center line.
2. Instead of continuous injection process WAG process were used. Initial WAG cycle slug volume were, 6% HCPV of CO_2 which was followed by 2.8% HCPV of water. He WAG ratio 0.47:1. This ratio was changed to 0.6:1 and slugs volumes were 6% HCPV of CO_2 which was followed by 3.6% HCPV of water.
3. A pre-water slug of 6% HCPV to be injected for the pattern areas where reservoir pressure is below 1600 psi before the CO_2 injection to enhance the pressure of the reservoir. The value of 1600 psi was based on the slim tube test recovery.

200 MMcf/d was the total delivery rate of CO_2 from the supply system which was planned. However this rate of supply was equivalent to about 1/3rd of the total requirement of injection pattern. Therefore the injection fields were divided into three areas mainly phase 1, phase 2 and phase 3 which is almost equal pore volumes of hydrocarbon. Phases are shown in the map in appendix VII. Plan was such that, all the available CO_2 was injected in to phase 1 till HCPV slug 6% then focus on phase 2, mean while 2.8% HCPV slug of water was injected in phase 1. This interface area of WAG process implemented between the phases 1 and phase 2 and expanded to phase 3 as the requirement of CO_2 in phase 1 reduced eventually.

Full scale program for pressure maintenance through water flooding has started in the year 1954 throughout the unit area. 72 of the water injection well were selected initially, the location of the selected wells was along the longitudinal crest of the structure shown in figure below,

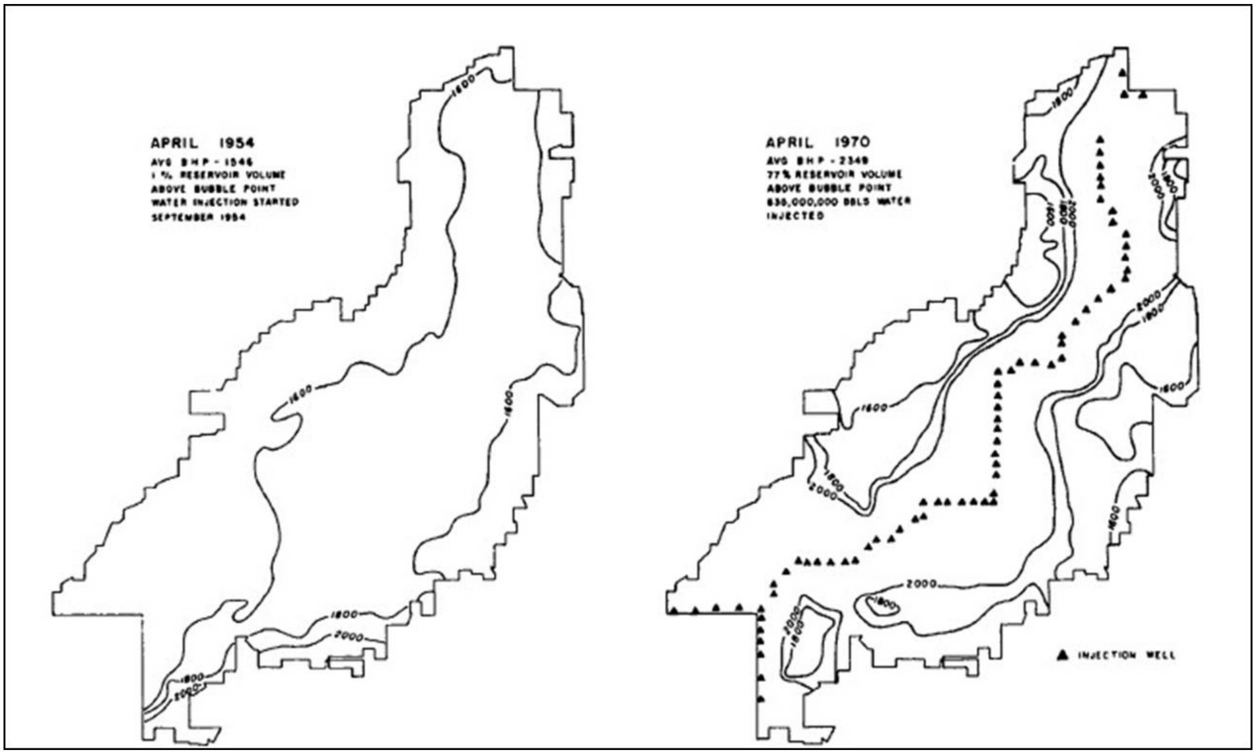


Figure 8: Bottom-hole pressure map (Dicharry, Roy M., T.L. Perryman, and J.D. Ronquill, 1973)

These selected wells were selected due to gas saturation conditions and critical pressure which was existed as well as apparent necessity for quick restoration of pressure. The rate of water injection was 13000 to 14000 B/D through these selected well which was regulating production under combined operations. The exercise proved to be effective and the pressure of the reservoir was built up successfully. It was found that the response of the reservoir was quick to this program and the bubble point pressure was above only 1 % of its volume before actual start of the injection. Within less than 2 years of injection almost 45 % was beyond the bubble point pressure whereas after 7 years of injection only 80 % was above bubble point pressure. The performance of the water flooding through center line proved to be effective and extremely motivating, on the other hand the huge quantum of oil would remain in the reservoir at the end of this program and it needed advanced technological studies to be involved, which was started in the year 1968. The studies are mainly concerned to find out the ways to extract additional quantum of oil economically. The SACROC reservoir have mobility ratio of 3, which is uniquely favorable for water and oil at the reservoir conditions. This unfortunately ceases the possibility to add mobility controlled material to the water to enhance the efficiency of the program. To improve recovery of the oil the best potential way was to reduce the oil saturation in the swept area. After re-pressuring program of the SACROC oil field through water injection, it was ideal to implement miscible recovery process to extract more oil due to reservoir pressure and properties of oil. As the average pressure of the reservoir is quiet low for the miscibility of the dry gas with fluid hence the idea of re-infecting dry residue gas was overruled. Two feasible alternatives were agreed upon was to use residue gas supplemented with propane and other is using carbon dioxide miscible slugs. Bothe the process have been evaluated for the SACROC unit. For the pattern injection program, it was predicted that water will follow the HPV slugs of this mixture. The results thereafter shows that 11 % incremental oil recovery efficiency indicated in the processed area as compared to plain water flood. On the other hand high cost of the material which is injected as well as high risk of viscous fingering and gravity override affects the economics of the enriched gas miscible program and thus it became less attractive over the selected CO_2 slug process (Dicharry et al., 1973).

The leading edge of the water denoted by the line was updated based on actual breakthrough of the water. The pattern selected was inverted nine spot, some of them were partially behind the water flood's leading edge. It is necessary to note that leading edge of the water injection have substantial amount of oil which was waiting to process through CO_2 injection, on the other hand some of the patterns were non-invaded spaces of the reservoir. 202 numbers of injection wells were designed to process around 49 % of the hydrocarbons originally in place. Figure 15 shows the leading edge position of the waterfront's center line as well as injection wells and the phase area of CO_2 injection program. The field was processed by three phase areas as supply rate of CO_2 are limited to approximately 200 MMcf/D or 136000 RB/D (Dicharry et al., 1973).

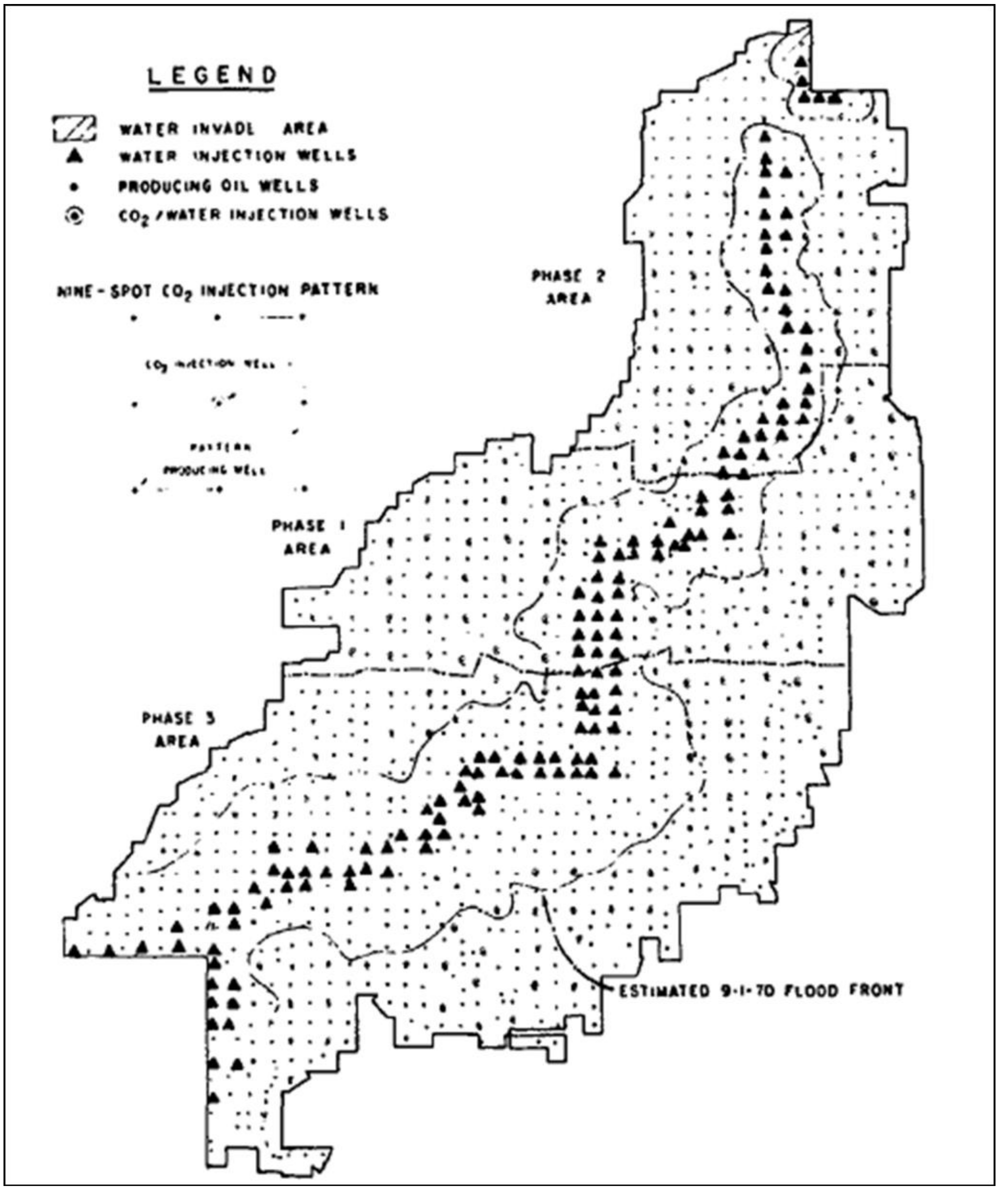


Figure 9: CO_2 Pattern injection wells

Challenges

There are large numbers of parameters as well as strategies that are involved to achieve objectives of maximum recovery as well as storage to flood the reservoir. Now, for an example, oil recovery can be greatly enhanced for the gravity stable displacement of the carbon dioxide as well as stored amount of carbon dioxide due to comparatively small amount of injections as well as production rates in some oil reservoirs. However it has been observed that this types of floods gives good oil recovery in the reservoirs with the considerable dip and very high permeability.

One of the major challenges in carbon dioxide flooding project is spacing between the wells. It is necessary to provide optimum spacing between the wells to achieve goals of maximum oil recovery and the maximum storage. It is interesting to know that, if wells are place far apart then it takes more time for carbon dioxide to breakthrough in to the production wells which apparently results in increase in carbon dioxide storage. On the other hand if spacing between the wells are narrow then it causes holdup the oil production peak.

Reservoir parameters also affect the design of carbon dioxide flooding as well as the objectives of the projects. For an example, cross flow and gravity override are affected by the vertical to horizontal permeability ratio. Reservoir heterogeneity is one of the most important characteristics of any reservoir. The cost is very high to re inject produced carbon dioxide due to the recycling plant at injection site. Table 12 below shows pros and cons of few field other than Kelly Snyder based on type of injection implemented.

Table 12: Pros and cons

	Field case	**Pros**	**Cons**
WAG (TWAG)	Slaughter Wasson	Control on co2 and mobility utilization factor is improved	Concentrated operational adjustment is required along with broad field investigation program
Continuous injection	Wellman Dollarhide	Recovery is higher at early stages	Possibility of higher carbon dioxide purchase which limits field operations.
Cyclic injection	Big Sinking Field Central Vacuum Unit	lower investment and formation of tights	It need to shut the well so carbon dioxide can be dissolved and dissipate which reduces the productivity

Conclusion

The chapter is predominantly focused on the largest oil producing field in the United States i.e. Kelly Snyder. Introduction chapter illustrate brief background of the oil field about its initial exploration and the location of the field. Which is followed by the reservoir geology, the section discuss various patterns and reef formation within the location, and it also discuss different rock formation and types within the area of interest. Reservoir parameters are one of the most important factors one has to consider before designing the production as well as injection wells. The reservoir data is illustrated in the table in three part, physical features of reservoir, Properties of Reservoir Rock and unit hydrocarbon pore volume. The fluid parameter shows the properties of the oil within the reservoir such as composition on fluid, bubble point pressure, fluid viscosity and density. Oil in place and recoverable reserves discuss the actual oil that is available within the reservoir initially and at the present state along with the average recoverable reserves through the reservoir. Initial distribution system gives overview of distribution system within the area. Oil production section is divided in to two parts, it gives systematic overview of production history along with small case study depicting comparison between CO_2 WAG and pattern water flooding. Injection strategy section provide the brief background of water flooding that followed with the carbon dioxide injection along with relevant geographical figures. The Chapter is completed with illustrating the challenges faced by engineers due to various parameters.

Chapter 4: Results

Introduction to MBAL software

MBAL is a reservoir engineering tool-kit which is commercialized in the year 1990. The main intention to develop the tool was to assist the reservoir engineers especially in their analytical studies of the reservoir. The simulation software include material balance calculation, however it is not limited to material balance calculations only. Some of the other module asides material balance includes 1D model, Decline curve analysis, Monte Carlo simulation, reservoir allocation, coal bed methane, streamlines and tight reservoir analysis. It is possible to use these techniques in combination or in isolation depending upon the goal of the simulation analysis. For an example, name of one of the program is material balance calculations which has many advantages over classical material balance calculations which is found in the theory and it is a core functionality of the MBAL. Reservoir engineers may use novel approaches aside from the usual task such as understanding the drive mechanism and allowing engineers to evaluate the gas or oil originally in the well, for an instance using relative permeability curves as well as multi tank modeling they can perform prediction, which ensures that the MBAL is capable of provide sturdy platform on which physics of reservoir as well as plans of production can be studied in detail.

a) **Material balance-** Non dimensional reservoir analysis can be conducted in the MBAL for the oil field throughout its life. Non dimensional analysis can be conducted for the mature field where the complete data is available as well as for the new field in its early stages when the data available is limited. Therefore, it is possible to apply this tool for the entire life of the reservoir due to its capabilities. This is also used in combination with numerical simulator for a quality check as well as for matching of the history or for a proxy model for quick analysis. MBAL allows engineers to use limited data such as pressure, volume, temperature and cumulative production to find out quantity of oil in the reservoir and the associated drive mechanism if any, thus engineer are well equipped with this tool kit even if with limited data. It is possible to determine any hydrocarbon fluid such as oil, gas, condensate by help of compositional description and black oil one or the other, in situations where the pressure, volume and temperature varies with the depth (Note- In high relief reservoirs compositional gradients are important). MBAL have capacity to model compartmentalized reservoirs along with partial sealing faults or faults due to pressure activation. It is possible to match history by modeling multi tank models with transmissibilities. The development of the material balance idea is an additional improvement from the experts in the field of petroleum engineering which offers the vast application in the entire filed life.

b) **History matching-** This is one of the progressive menu option of MBAL which helps engineers to analyze the results logically through the process of history matching. The industry standard techniques such as Cole, Campbell, P/Z plots are used to plot the graphs of history matching. Drive mechanisms of the location can be identified by the process of history matching as well as it allows whether the measured data entered is to be trusted. Existing analytical method which is available within MBAL to match the history of the analytical model; two valuable results can be achieved through running the simulation of the available history. Initially, historical period can be run within the simulation which helps am engineer to compare the predicted production profiles by the model and the data which is entered in the software, if it is a close match then its shows the good match of the history. Now, secondly, MBAL runs the history as a prediction it calculates entire historical production profile, reservoir pressure as well as saturations in the past period (Historical period). The custom relative permeability curves can be created by using these historical periods and can be calibrated to the history matched model. It is possible to enter the data on the basis of tank or on the basis of well by well. Relative permeability curves can be obtained in the latter context for area of draining of each well using the procedure explained above. Capability of MBAL allows the analytical model to approach to the reality which is far better than the model based on classical literature.

c) **Aquifer modeling-** MBAL facilitate vast matching facilities which allows it to model the strength as well size of the drive mechanism. This is possible if historical production and PVT of the existing reservoir is known. It is possible to model both transient as well as steady state responses within MBAL which conforms the modified models by petroleum experts and the industry standards. The aquifer sizing which is primarily based on pressure support response which offers the path to calibrate the actual physics against the data of production, so once calibrated it can be used to predict.

d) **Forecasts-** There are two ways through which MBAL can be utilized to perform predictions or forecasting, a) In an integrated model it can be used as reservoir tool Or it can be used as separate reservoir analysis tool kit. The calculation can be very fast in both the cases considering history matched aquifer as well as relative permeability as the source of calculations for predictions. Relative permeability curve can be generated by using the model developed by history matching. These curves are physical representative of the phase flow that shows how one phase is moving relative to another within the area of well drainage. This curves also depict the well positioning within the reservoir. Therefore two well within the single homogeneous tanks to show different production profile.

e) **1D model-** The study of the displacement of oil by water is carried out in the 1D model by using Buckley Leveret and fractional flow equations for a single layer. The set of multilayer curves are set by multilayer tool in multilayer context for every layer using the immiscible placement theories which predominately use theories of Stiles, Buckley Leveret, L P Dake which is theory of communicating layers and single simulation cell. Once the profiles are generated then it can be easily brought to the tool developed for material balancing to continue with matching and further analysis.

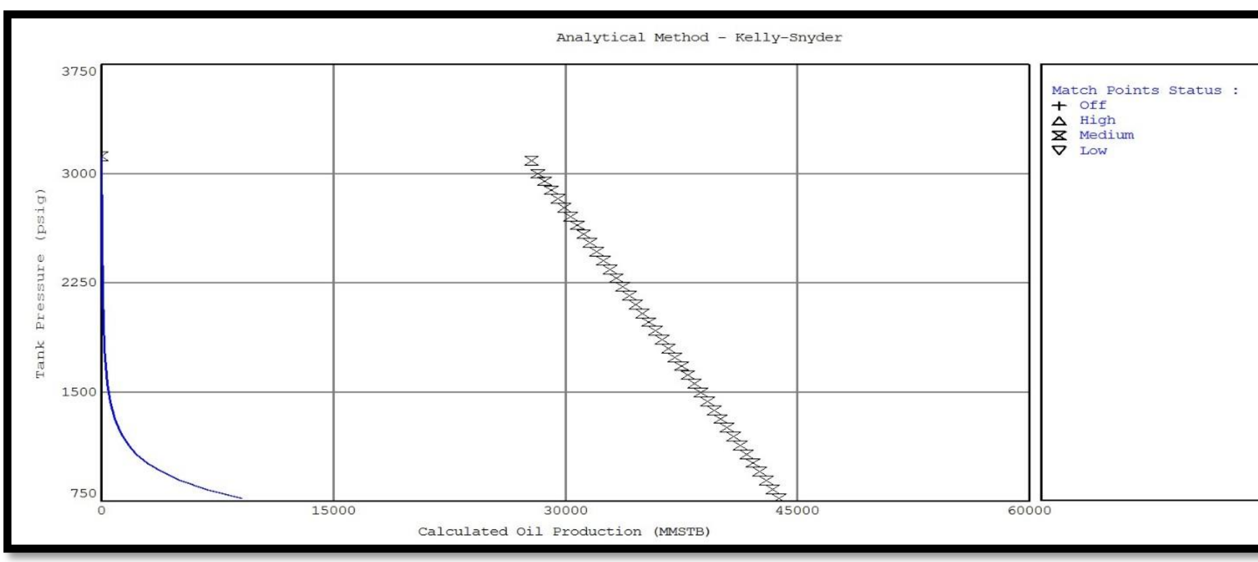
f) **Multilayer production-** The wells have been built in multiple layers, the production can be achieved through several producing intervals in the field. Therefore it is expected to calculate the rate of the production at a surface instead of layers whereas classical method uses basis of permeability and pay height to allocating production. Novel modifications have been made to the traditional allocation method. This uses IPRs to perform this allocation. Once allocation have been made then the rates can be brought back to material balance tool and matching of the history is performed according to the usual practice. This is performed iteratively until the matching of the history is achieved.

A methodological reservoir engineering and simulation analysis has been carried out using MBAL tool. The model developed was single tank which is used to determine and analyze reservoir performance based on two scenarios, namely performance of reservoir before employing carbon dioxide EOR and performance of reservoir after using carbon dioxide EOR by using the plots obtain through simulation results. The analysis is run until December 1991 for first scenario whereas for carbon dioxide EOR performance it is run till December 1999. The response analysis in MBAL is continued till abandonment pressure, at the point of production which is uneconomical to continue the production further.

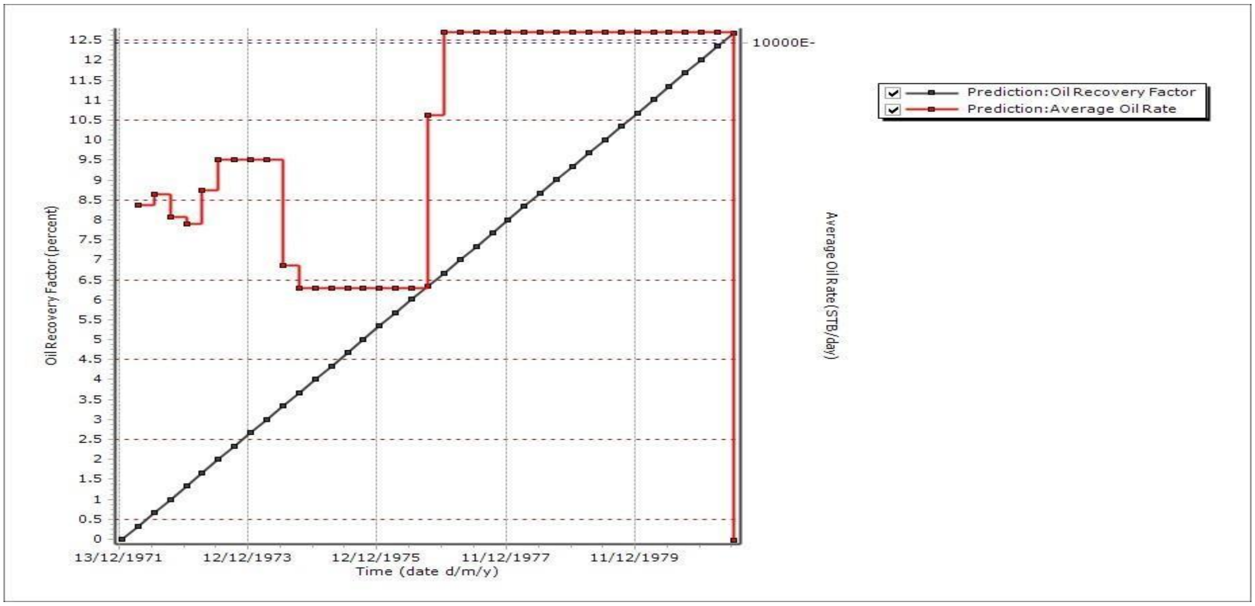
There are two sub sections in this chapters which shows different performance results for the two scenarios discussed earlier. The results of before and after carbon dioxide EOR is discussed considering the performance plots.

Results before CO_2 EOR

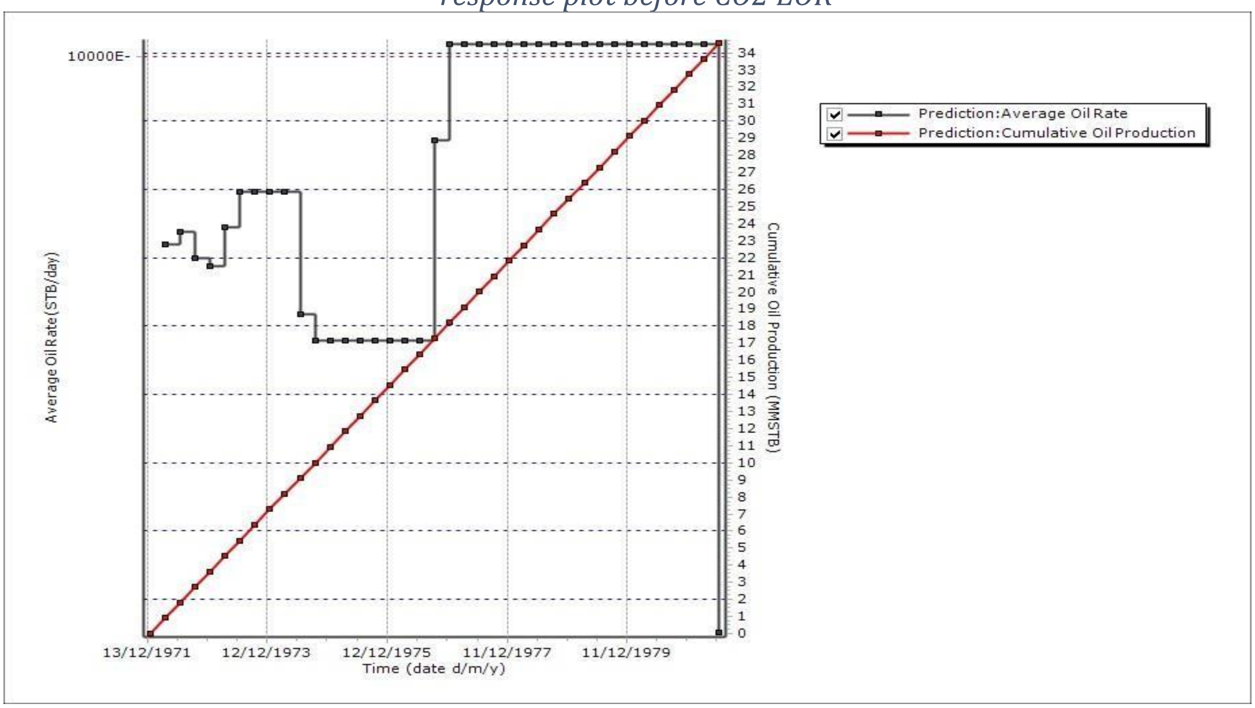
Below graphs shows the results obtained after incorporating CO_2 EOR in the field. It is necessary to note the single tank system is used to pursue the simulation.



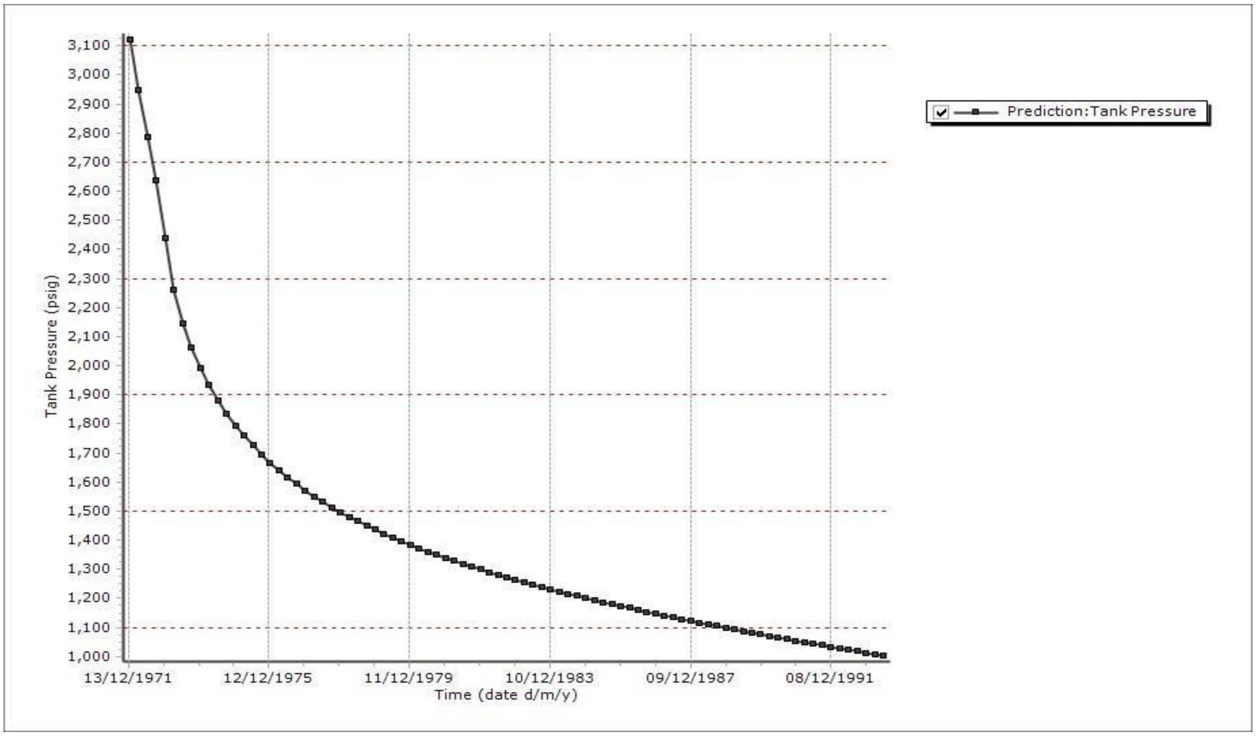
Graph 8: Tank pressure (psig) vs oil production (MMSTB)



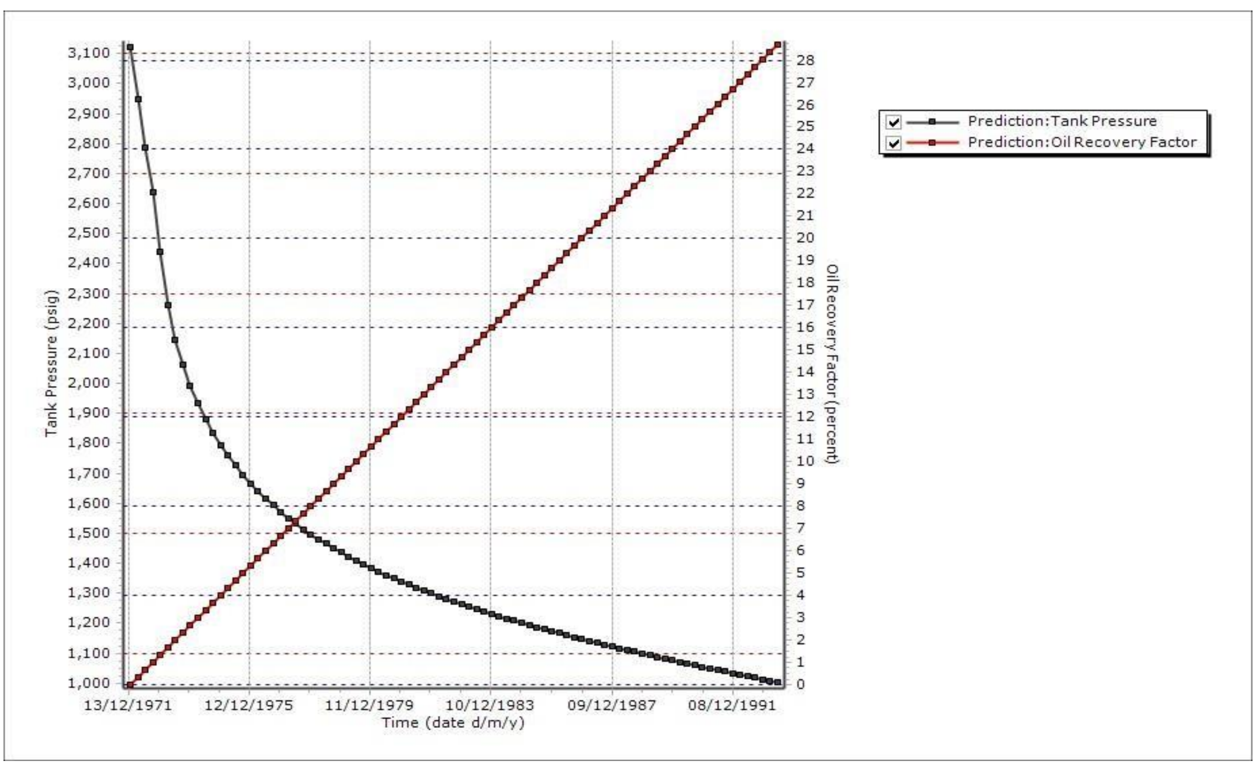
Graph 9: Prediction of Reservoir oil production profile and recovery factor performance response plot before CO2 EOR



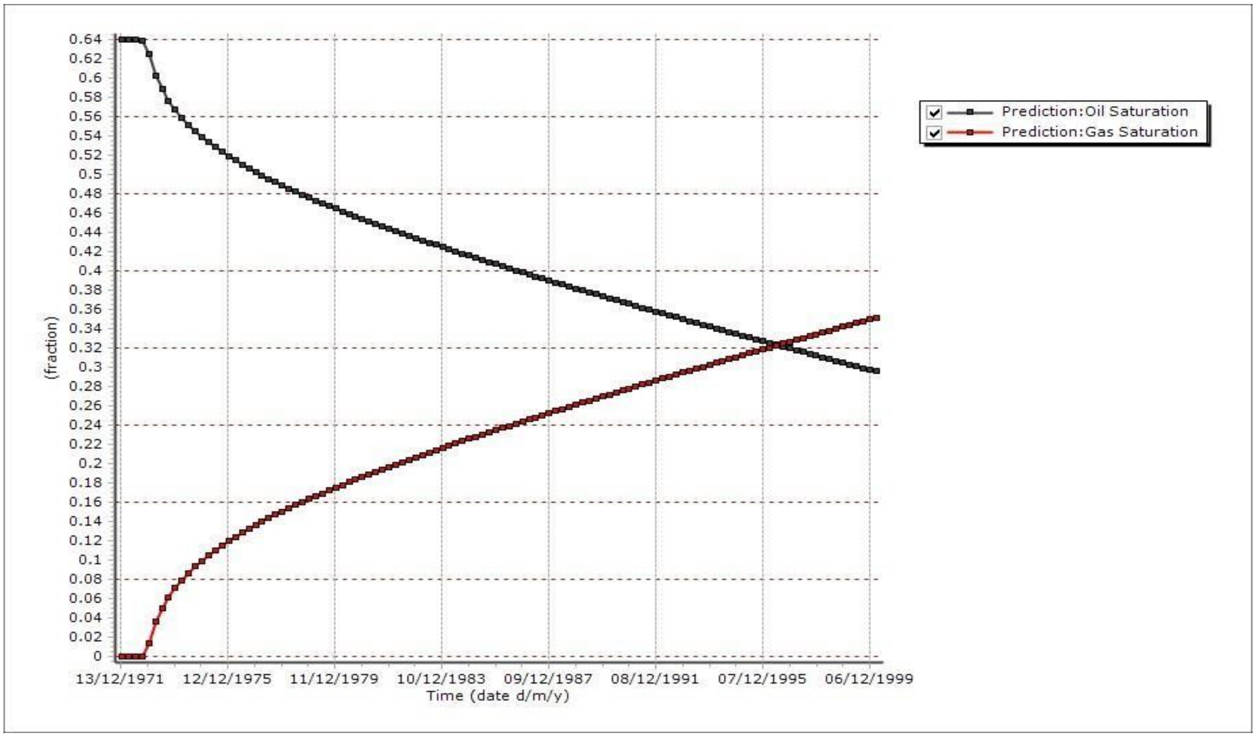
Graph 10: Prediction of average oil rates and cumulative oil production performance response plot before CO2 EOR



Graph 11: Prediction of Reservoir oil pressure response plot before CO2 EOR



Graph 12: Prediction of Reservoir oil pressure and oil recovery factor response plot before CO2 EOR



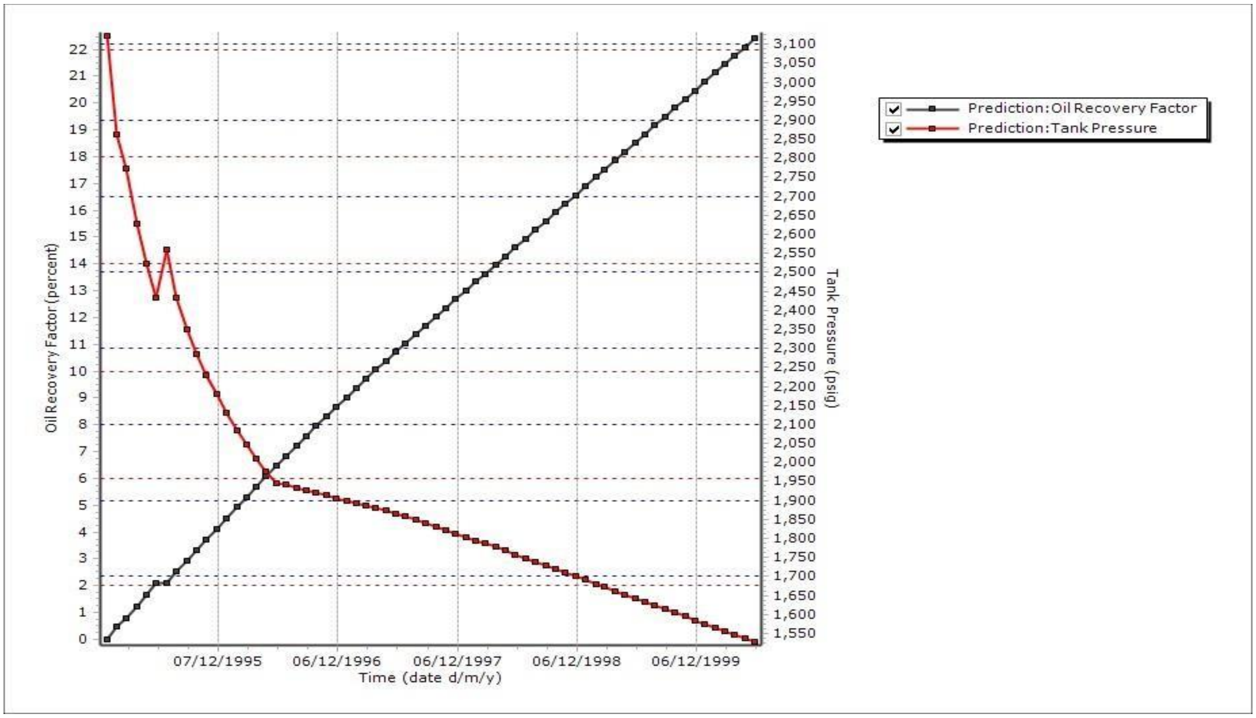
Graph 13: Oil and gas saturation response plot before CO_2 EOR

Table 13: Analytical plot value before CO_2 EOR

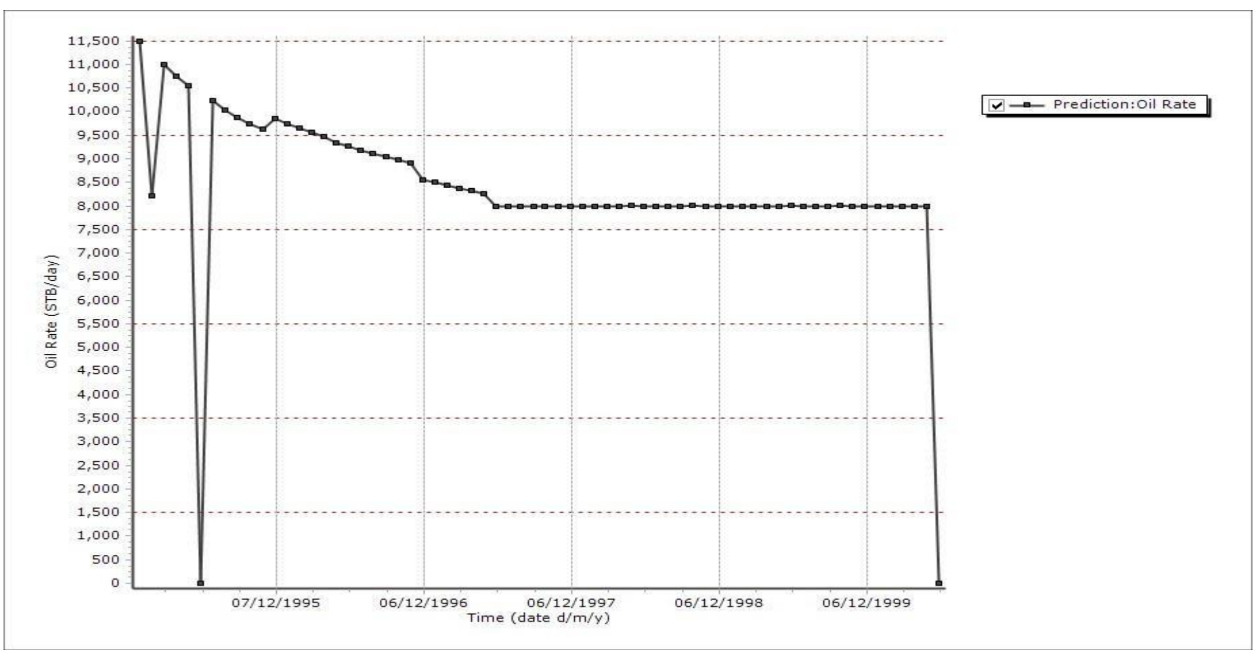
Parameter	**Value**
Tank temperature (^{0}F)	130
Tank pressure (psig)	3122
Tank porosity (Fraction)	0.76
Water saturation (Fraction)	0.36
Water compressibility (1/psi)	-
Formation compressibility (1/psi)	3.2×10^{-6}
Initial Gas cap ratio	0
Oil in place (MMSTB)	2727
Production start	1/1/1972
Aquifer model	None
Aquifer system	Radial aquifer

Results after CO_2 EOR

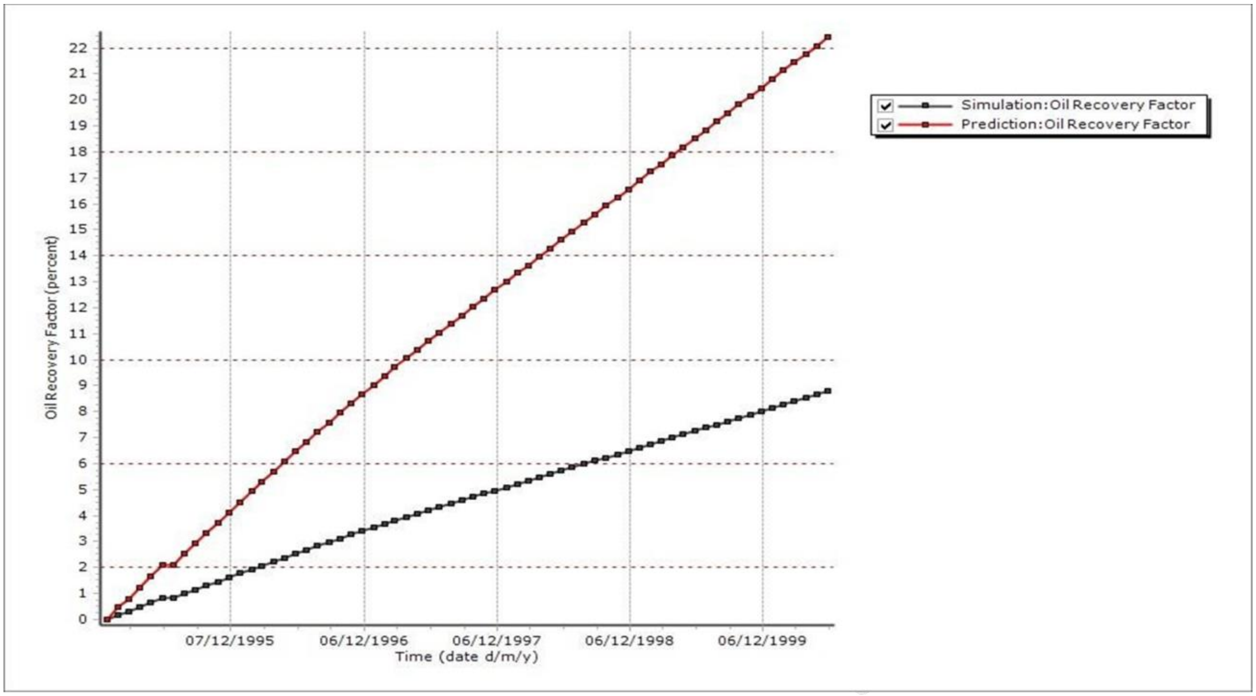
Below graphs shows the results obtained after incorporating CO_2 EOR in the field. It is necessary to note the single tank system is used to pursue the simulation.



Graph 14: Oil recovery factor and tank pressure response after CO_2 EOR



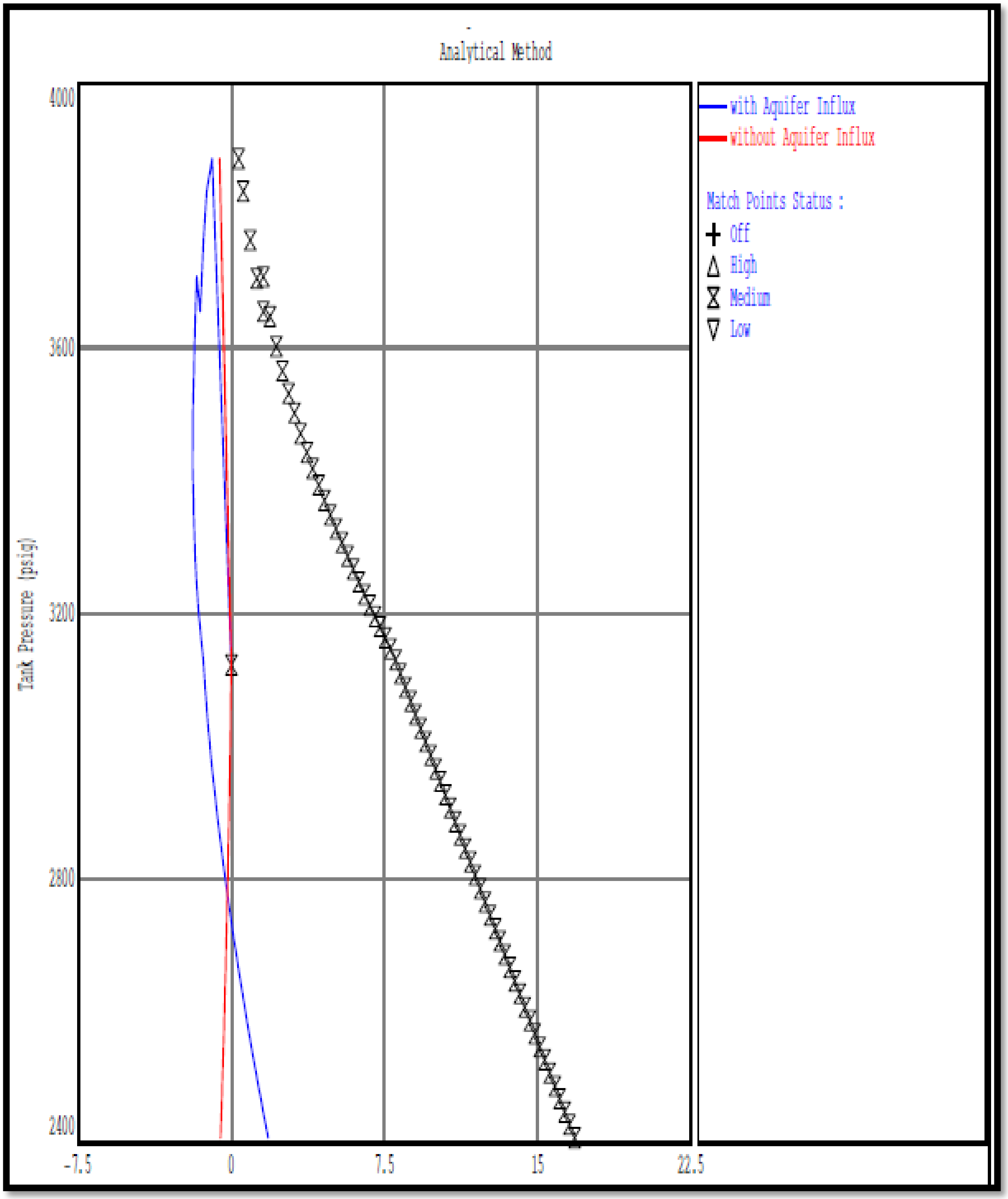
Graph 15: Oil recovery factor and tank pressure response after CO_2 EOR



Graph 16: Oil recovery factor and tank pressure response after CO_2 EOR

Table 14: Analytical plot value after CO_2 EOR

Parameter	**Value**	Production start	1/1/1995
Tank temperature (^{0}F)	130	Aquifer model	Hurst-van Everdingen-Modified
Tank pressure (psig)	3122	Aquifer system	Radial aquifer
Tank porosity (Fraction)	0.25	Outer/inner radius	99.8
Water saturation (Fraction)	0.25	Encroachment Angle (degrees)	6.31048
Water compressibility (1/psi)	3 X 10-6	Calc. Aquifer Volume (MMft^3)	1.57159×10^8
Formation compressibility (1/psi)	3.25625×10^{-6}	Aquifer Permeability (md)	0.0891911
Initial Gas cap ratio	0	Tank Thickness (feet)	250
Oil in place (MMSTB)	1703.13	Tank Radius (feet)	2500



Graph 17: Tank pressure (psig) Oil production (MMSTB) after CO_2 EOR

Comparison of results with actual field implementing CO_2 EOR

The data of actual field is acquired from the document prepared by advanced resources international in the year 2006. This data is compared with the simulation prediction results obtained through MBAL software to evaluate similarity and discrepancy in the results.

Table 15: Comparison of results with actual field data

Parameters	**Actual Field**	**MBAL**	
	CO_2 EOR	**CO_2 EOR**	**Before CO_2 EOR**
Oil in place (MMSTB)	2113	1703.13	2727
Number of producing well	300	-	0
Number of injectors	300	-	0
Recovery factor (%)	24	22.5	12.5
Production (MMSTB)	200	0.56	0.39
Rate per day (STB/d)	23000	8494	10000
Oil viscosity (Centipoise)	0.35	0.95898	0.93241
Oil Density (lb/ft3)	41.8	46.878	47.364
Cumulative GOR (scf/STB)	1000	500	1000
Water Cut (%)	36	17.862	7.41

Chapter 5: Discussion

The results obtained through MBAL software are discussed individually based on the graphs. The later sub chapter discusses these MBAL results with the actual field values for better understanding of the results.

Discussion for the results obtained before CO_2 EOR

In this section, the response of reservoir to conventional oil production system is discussed and analyzed. Consequently oil recovery factor, average rate of oil production was found that are the alternative response for the application of field development.

1. **Field oil production and oil recovery factor**

Graph below shows the prediction of average oil production and oil recovery factor profile before the use of carbon dioxide EOR. Average oil production rate is increasing at the rate of 8.4 STB/day in the year 1971 whereas in the year 1976 the average rate of oil production has reached 10.6 STB/d. From the graph it can be observed that the peak rate for production remained for four years from the year 1976 to 1980 at a rate of 12.7 STB/day. On the other hand, average oil production seems to be declined rapidly in the year 1980. Oil recovery factor is increasing exponentially from 0.4% at the beginning and it is constant throughout the years 1971 to 1980, therefore overall recovery factor is 0.4%.

2. **Field pressure and cumulative oil production profile**

Graph below shows the prediction of Kelly Snyder oil field's reservoir pressure profile and cumulative oil production before carbon dioxide EOR. Cumulative oil production increases from 1971 to 1980 at a rate of 1 MMSTB/day and it is at peak in the year 1980 which is 34 MMSTB/day. The oil production rate is increased rapidly as the cumulative oil production is increased by 1 MMSTB/day throughout the years 1971 to 1980. Tank pressure on other hand is decreasing exponentially as shown in the graph 9. The tank pressure is reduced rapidly since 1971 to 1974 at an average rate of 2600 psig and since 1975 an average rate of 200 psig till abandonment pressure of approximately 500 psig in year 1991. The field reaches its end of life without carbon dioxide EOR in the year between the years 1990 to 1991.

3. **Field pressure and oil recovery rate profile**

Graph shows the prediction profile for field pressure and oil recovery rate. Oil recovery rate of the field is increasing at a rate of 0.1% which is constant throughout the years 1971 to 1991 whereas pressure of the field is decreasing exponentially since year 1971 to 1991. Initially it was reduced with an average rate of 2600 psig till year 1975 and later approximately average rate of 200 psig.

4. **Oil and gas saturation response**

Graph below demonstrate prediction of gas and oil saturation fraction of the Kelly Snyder oil field. Oil saturation fraction is reduced exponentially whereas gas saturation fraction is increasing exponentially between the years 1971 and 1999. It means saturation of the gas fraction inversely proportional to the soil saturation fraction. Hence with higher the oil saturation, lower the gas saturation and vice versa.

Discussion for the results obtained after CO_2 EOR

This section illustrate the reservoir response after incorporating carbon dioxide EOR. Consequently oil recovery factor, average rate of oil production was found that are the alternative response for the application of field development.

1. **Tank pressure and oil recovery factor response**

Graph below shows the response of Kelly Snyder field after considering carbon dioxide EOR between the years 1994 to 1999. The pressure of the system reduced inconsistently unlike the response of the system before implementing carbon dioxide EOR, which was exponential decrease. Here, pressure is decreased till mid of year 1994 till 2450 psig and sudden increase can be observe up to 2550 psig which again reduced at the rate of 100 psig. On the other hand oil recovery factor is increasing at a rate of 0.4 % which almost same throughout the years and reached up to 22%.

2. Oil rate response profile

The graph below shows the oil rate response of the Kelly Snyder oil field to carbon dioxide EOR. In the first half of the year 1994, oil rate is uneven and can see major variation, but once the EOR method have been implemented, the oil rate has jumped to 10000 STB/day in mid-1994, which is then gradually reduced till mid of 1997 to 8000 STB/day. Oil rate is constant over three years from mid of 1997 to mid of 1999 at an average of 8000 STB/day.

3. Oil recovery factor response (Simulated and predicted)

Graph below shows response of oil recovery factor after implementing carbon dioxide EOR. The graph shows two separate profile curves black being simulation profile curve of oil recovery factor whereas red being prediction profile curve of oil recovery factor. Prediction shows high oil recovery factor which is increasing up to 22.5 % at a rate of 0.4% on the other hand simulation profile curve shows lower oil recovery factor up to 9 % with an increase at a rate of 0.2 %.

Discussion of the simulation results with actual field production by CO_2 EOR

Oil in place for simulation before CO_2 EOR is 2727 MMSTB and for CO_2 EOR it is 1703.13 MMSTB, whereas in actual CO_2 EOR the oil in place is 2113 MMSTB. The MBAL simulation used single tank system through which entire simulation run is carried out, on the other hand for actual CO_2 EOR system implemented in the Kelly Snyder oil field has 300 number of injectors as well as producing well. Recovery factor seems to be improved for CO_2 EOR in simulation (22.5%) as well as in actual practice (24%) when compared to simulation values before implementing CO_2 EOR (12.5 %). The values obtained for recovery factor through simulation and actual values are close to each other. Huge difference can be seen in production as well as rate per day values, actual field value after implementing CO_2 EOR is 23000 STB/day whereas in simulation it is 8494 STB/day. Production before implementing CO_2 EOR was 10000 STB/day according to simulation. Oil viscosity is nearly same for both simulation which is close to 0.94 centipoise which is greater than actual field's oil viscosity 0.35 centipoise. Oil density values for actual as well as both the simulation are in the close range of 41 lb/ft^3 to 47.5 lb/ft^3. Gas oil ratio for simulation before CO_2 EOR and actual ratio after CO_2 EOR are similar i.e. 1000 scf/STB, whereas Gas oil ratio for simulation after CO_2 EOR is 500 scf/STB. Water cut for actual field after implementing CO_2 EOR was 36% whereas it is 17.9% for simulation of CO_2 EOR condition and 7.41% for simulation before CO_2 EOR conditions.

The difference in the results are due to following reasons,

1. Results of simulation is greatly dependent on the input values, also the simulation environment is unaffected by external surroundings. On the other hand actual field outputs are dependent on various parameter such as composition of CO_2, pressure, temperature etc. which are constantly changing in addition to that weather plays important role in transporting CO_2, which cannot be simulated exactly in the software.
2. Number of producing as well as injecting wells in actual field are 300 whereas the simulation is carried out on the basis of single tank with 0 injectors and wells. This might have been the source of discrepancy in actual and simulated conditions results.

Chapter 6: Conclusion and recommendations

MBAL simulator is used to analyses the reservoir system before and after the carbon dioxide EOR method. The single tank multi component system was modelled to predict the performance response of the reservoir. Below table is the summary of the results obtained through the simulation results. The sensitivity analysis shows the massive difference between the results obtained through MBAL simulation. The oil recovery factor response improves for the analysis conducted for EOR which is approximately 23 % as compared to recovery factor of 12.5 % before employing EOR. Approximate increase in IOR displacement efficiency is about 84%.

Table 16: Summary of performance response

Performance indicator	Model	Value
Cumulative Oil produced (MMSTB)	Before EOR	34
	After EOR	?
Oil Rate (STB/Day)	Before EOR	10000
	After EOR	8000
Oil recovery factor (%)	Before EOR	12.5
	After EOR	22.5

Cumulative oil production before EOR is close to 34 MMSTB whereas it is ? as compared to earlier scenario. The IOR displacement efficiency has increased to ?%

Oil rate have been decreased for the simulation response obtained for carbon dioxide EOR simulation up to 8000 STB/day as compared 10000 STB/day. The IOR displacement efficiency is reduced by 25%.

From the results obtained through simulation it has been found that the carbon dioxide EOR improves the amount of oil recovery from the Kelly Snyder reservoir. The oil recovery factor of the field increases due to injection of the carbon dioxide which results production increase as compared to the system before implementing carbon dioxide EOR.

Recommendations

- Integrated well design system model can be generated by using PROSPER by using the obtained results through MBAL. It is possible to initialize PROSPER into the MBAL. On the other hand the simulator tool ECLIPSE can be utilized for well design as well as reservoir features.
- To enhance the quality of performance simulation of reservoir system actual carbon dioxide flood test as well as single well chemical tracer test needed to be investigated in order to generate specific permeability model and sensitivity analysis of these relative permeability model.
- It is very important to analyses the economic aspect of carbon dioxide EOR system to understand its effect on oil prices and co relate it to world market

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APPENDICES

Appendix I: Tank input data history before CO_2 EOR

Table 17: Highlights of production prediction (1972 to 2000)

Time	Reservoir Pressure	Oil recovery factor	Avg. oil rate	Avg. gas rate	Avg. Water rate	Avg. liquid rate
(Date)	(psig)	(%)	(STB/day)	(STB/day)	(STB/day)	(STB/day)
1/1/1972	3122	0				
1/4/1972	2949.12	0.33	10000	10	800	10800
1/7/1972	2788.58	0.67	10000	10	800	10800
30/09/1972	2639.65	1	10000	10	800	10800
30/12/1972	2437.81	1.33	10000	10	800	10800
31/03/1973	2259.78	1.67	10000	10	800	10800
30/06/1973	2147	2	10000	10	800	10800
29/09/1973	2061.37	2.34	10000	10	800	10800
29/12/1973	1991.61	2.67	10000	10	800	10800
30/03/1974	1932.55	3	10000	10	800	10800
29/06/1974	1881.29	3.34	10000	10	800	10800
28/09/1974	1836.02	3.67	10000	10	800	10800
28/12/1974	1795.52	4	10000	10	800	10800
29/03/1975	1758.91	4.34	10000	10	800	10800
28/06/1975	1725.54	4.67	10000	10	800	10800
27/09/1975	1694.92	5.01	10000	10	800	10800
27/12/1975	1666.66	5.34	10000	10	800	10800
27/03/1976	1640.44	5.67	10000	10	800	10800
26/06/1976	1616	6.01	10000	10	800	10800
25/09/1976	1593.14	6.34	10000	10	800	10800
25/12/1976	1571.68	6.67	10000	10	800	10800
26/03/1977	1551.46	7.01	10000	10	800	10800
25/06/1977	1532.36	7.34	10000	10	800	10800
24/09/1977	1514.26	7.68	10000	10	800	10800
24/12/1977	1497.08	8.01	10000	10	800	10800
25/03/1978	1480.72	8.34	10000	10	800	10800
24/06/1978	1465.12	8.68	10000	10	800	10800
23/09/1978	1450.21	9.01	10000	10	800	10800
23/12/1978	1435.92	9.34	10000	10	800	10800
24/03/1979	1422.22	9.68	10000	10	800	10800
23/06/1979	1409.06	10.01	10000	10	800	10800

09-03-91	1049.6	25.69	10000	10	800	10800
08-06-91	1044.32	26.03	10000	10	800	10800
07-09-91	1039.07	26.36	10000	10	800	10800
07-12-91	1033.87	26.7	10000	10	800	10800
07-03-92	1028.7	27.03	10000	10	800	10800
06-06-92	1023.56	27.36	10000	10	800	10800
05-09-92	1018.46	27.7	10000	10	800	10800
05-12-92	1013.39	28.03	10000	10	800	10800
06-03-93	1008.35	28.36	10000	10	800	10800
05-06-93	1003.34	28.7	10000	10	800	10800
04-09-93	998.36	29.03	10000	10	800	10800
04-12-93	993.41	29.37	10000	10	800	10800
05-03-94	988.48	29.7	10000	10	800	10800
04-06-94	983.57	30.03	10000	10	800	10800
03-09-94	978.69	30.37	10000	10	800	10800
03-12-94	973.83	30.7	10000	10	800	10800
04-03-95	968.99	31.03	10000	10	800	10800
03-06-95	964.18	31.37	10000	10	800	10800
02-09-95	959.38	31.7	10000	10	800	10800
02-12-95	954.6	32.04	10000	10	800	10800
02-03-96	949.84	32.37	10000	10	800	10800
01-06-96	945.1	32.7	10000	10	800	10800
31-08-96	940.38	33.04	10000	10	800	10800
30-11-96	935.67	33.37	10000	10	800	10800
01-03-97	930.97	33.7	10000	10	800	10800
31-05-97	926.29	34.04	10000	10	800	10800
30-08-97	921.62	34.37	10000	10	800	10800
29-11-97	916.97	34.7	10000	10	800	10800
28-02-98	912.33	35.04	10000	10	800	10800
30-05-98	907.7	35.37	10000	10	800	10800
29-08-98	903.09	35.71	10000	10	800	10800
28-11-98	898.48	36.04	10000	10	800	10800
27-02-99	893.88	36.37	10000	10	800	10800
29-05-99	889.3	36.71	10000	10	800	10800
28-08-99	884.72	37.04	10000	10	800	10800
27-11-99	880.15	37.37	10000	10	800	10800
26-02-00	875.59	37.71	10000	10	800	10800

Table 18: Production prediction run simulation before CO_2 EOR

Stream : Prediction

Time (date d/m/y)	Tank Pressure (psig)	Oil Recovery Factor (percent)	Oil Rate (STB/day)	Gas Rate (MMscf/day)	Water Rate (STB/day)	Liquid Rate (STB/day)	Avg.Oil Rate (STB/day)	Avg.Gas Rate (MMscf/day)
01/01/1972	3122.00	0.00	10000.0	10.0000	800.0	10800.0		
01/04/1972	2949.12	0.33	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
01/07/1972	2788.58	0.67	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
30/09/1972	2639.65	1.00	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
30/12/1972	2437.81	1.33	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
31/03/1973	2259.78	1.67	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
30/06/1973	2147.00	2.00	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
29/09/1973	2061.37	2.34	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
29/12/1973	1991.61	2.67	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
30/03/1974	1932.55	3.00	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
29/06/1974	1881.29	3.34	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
28/09/1974	1836.02	3.67	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
28/12/1974	1795.52	4.00	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
29/03/1975	1758.91	4.34	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
28/06/1975	1725.54	4.67	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
27/09/1975	1694.92	5.01	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
27/12/1975	1666.66	5.34	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
27/03/1976	1640.44	5.67	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
26/06/1976	1616.00	6.01	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
25/09/1976	1593.14	6.34	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
25/12/1976	1571.68	6.67	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
26/03/1977	1551.46	7.01	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
25/06/1977	1532.36	7.34	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
24/09/1977	1514.26	7.68	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
24/12/1977	1497.08	8.01	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
25/03/1978	1480.72	8.34	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
24/06/1978	1465.12	8.68	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
23/09/1978	1450.21	9.01	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
23/12/1978	1435.92	9.34	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
24/03/1979	1422.22	9.68	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
23/06/1979	1409.06	10.01	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
22/09/1979	1396.39	10.34	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
22/12/1979	1384.18	10.68	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
22/03/1980	1372.39	11.01	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
21/06/1980	1361.00	11.35	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
20/09/1980	1349.98	11.68	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
20/12/1980	1339.30	12.01	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
21/03/1981	1328.95	12.35	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
20/06/1981	1318.90	12.68	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
19/09/1981	1309.12	13.01	10000.0	10.0000	800.0	10800.0	10000.0	10.0000

19/12/1981	1299.62	13.35	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
20/03/1982	1290.36	13.68	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
19/06/1982	1281.34	14.02	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
18/09/1982	1272.54	14.35	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
18/12/1982	1263.95	14.68	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
19/03/1983	1255.56	15.02	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
18/06/1983	1247.36	15.35	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
17/09/1983	1239.33	15.68	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
17/12/1983	1231.47	16.02	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
17/03/1984	1223.77	16.35	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
16/06/1984	1216.21	16.69	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
15/09/1984	1208.81	17.02	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
15/12/1984	1201.54	17.35	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
16/03/1985	1194.39	17.69	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
15/06/1985	1187.37	18.02	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
14/09/1985	1180.47	18.35	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
14/12/1985	1173.68	18.69	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
15/03/1986	1167.00	19.02	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
14/06/1986	1160.42	19.35	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
13/09/1986	1153.93	19.69	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
13/12/1986	1147.54	20.02	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
14/03/1987	1141.23	20.36	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
13/06/1987	1135.01	20.69	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
12/09/1987	1128.87	21.02	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
12/12/1987	1122.80	21.36	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
12/03/1988	1116.81	21.69	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
11/06/1988	1110.89	22.02	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
10/09/1988	1105.04	22.36	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
10/12/1988	1099.25	22.69	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
11/03/1989	1093.52	23.03	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
10/06/1989	1087.85	23.36	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
09/09/1989	1082.24	23.69	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
09/12/1989	1076.67	24.03	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
10/03/1990	1071.17	24.36	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
09/06/1990	1065.71	24.69	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
08/09/1990	1060.29	25.03	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
08/12/1990	1054.92	25.36	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
09/03/1991	1049.60	25.69	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
08/06/1991	1044.32	26.03	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
07/09/1991	1039.07	26.36	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
07/12/1991	1033.87	26.70	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
07/03/1992	1028.70	27.03	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
06/06/1992	1023.56	27.36	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
05/09/1992	1018.46	27.70	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
05/12/1992	1013.39	28.03	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
06/03/1993	1008.35	28.36	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
05/06/1993	1003.34	28.70	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
04/09/1993	998.36	29.03	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
04/12/1993	993.41	29.37	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
05/03/1994	988.48	29.70	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
04/06/1994	983.57	30.03	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
03/09/1994	978.69	30.37	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
03/12/1994	973.83	30.70	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
04/03/1995	968.99	31.03	10000.0	10.0000	800.0	10800.0	10000.0	10.0000

03/06/1995	964.18	31.37	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
02/09/1995	959.38	31.70	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
02/12/1995	954.60	32.04	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
02/03/1996	949.84	32.37	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
01/06/1996	945.10	32.70	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
31/08/1996	940.38	33.04	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
30/11/1996	935.67	33.37	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
01/03/1997	930.97	33.70	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
31/05/1997	926.29	34.04	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
30/08/1997	921.62	34.37	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
29/11/1997	916.97	34.70	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
28/02/1998	912.33	35.04	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
30/05/1998	907.70	35.37	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
29/08/1998	903.09	35.71	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
28/11/1998	898.48	36.04	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
27/02/1999	893.88	36.37	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
29/05/1999	889.30	36.71	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
28/08/1999	884.72	37.04	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
27/11/1999	880.15	37.37	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
26/02/2000	875.59	37.71	10000.0	10.0000	800.0	10800.0	10000.0	10.0000
01/03/2000	875.39	37.72	10000.0	10.0000	800.0	10800.0	10000.0	10.0000

Avg.Water Rate (STB/day)	Avg.Liq Rate (STB/day)	Gas Saturation (fraction)	Oil Saturation (fraction)	Water Saturation (fraction)	Oil FVF (RB/STB)	Gas FVF (ft3/scf)	Water FVF (RB/STB)	Oil Viscosity (centipoise)
		0.0000	0.6400	0.3600	1.6045	0.00358	1.0037	0.43863
800.0	10800.0	0.0000	0.6397	0.3603	1.6083	0.00363	1.0042	0.43354
800.0	10800.0	0.0000	0.6395	0.3605	1.6123	0.00370	1.0047	0.42881
800.0	10800.0	0.0000	0.6393	0.3607	1.6164	0.00376	1.0051	0.42442
800.0	10800.0	0.0133	0.6256	0.3611	1.5861	0.00387	1.0057	0.43906
800.0	10800.0	0.0358	0.6029	0.3614	1.5328	0.00398	1.0062	0.47119
800.0	10800.0	0.0504	0.5881	0.3615	1.4999	0.00407	1.0065	0.49394
800.0	10800.0	0.0617	0.5767	0.3616	1.4754	0.00415	1.0068	0.51255
800.0	10800.0	0.0711	0.5672	0.3616	1.4558	0.00422	1.0070	0.52861
800.0	10800.0	0.0793	0.5590	0.3617	1.4393	0.00429	1.0072	0.54286
800.0	10800.0	0.0866	0.5517	0.3617	1.4252	0.00435	1.0073	0.55573
800.0	10800.0	0.0932	0.5451	0.3617	1.4129	0.00442	1.0075	0.56751
800.0	10800.0	0.0992	0.5391	0.3616	1.4020	0.00448	1.0076	0.57837
800.0	10800.0	0.1048	0.5336	0.3616	1.3922	0.00454	1.0077	0.58847
800.0	10800.0	0.1100	0.5284	0.3616	1.3834	0.00460	1.0078	0.59790
800.0	10800.0	0.1150	0.5235	0.3615	1.3753	0.00466	1.0079	0.60676
800.0	10800.0	0.1196	0.5189	0.3615	1.3679	0.00472	1.0080	0.61511
800.0	10800.0	0.1240	0.5146	0.3614	1.3611	0.00478	1.0080	0.62300
800.0	10800.0	0.1282	0.5104	0.3614	1.3548	0.00484	1.0081	0.63050
800.0	10800.0	0.1323	0.5064	0.3613	1.3489	0.00490	1.0082	0.63763
800.0	10800.0	0.1361	0.5026	0.3613	1.3434	0.00496	1.0082	0.64443
800.0	10800.0	0.1399	0.4989	0.3612	1.3383	0.00502	1.0083	0.65092
800.0	10800.0	0.1435	0.4954	0.3611	1.3334	0.00508	1.0083	0.65715
800.0	10800.0	0.1470	0.4919	0.3611	1.3289	0.00514	1.0084	0.66313
800.0	10800.0	0.1504	0.4886	0.3610	1.3246	0.00519	1.0084	0.66888
800.0	10800.0	0.1538	0.4853	0.3609	1.3205	0.00525	1.0085	0.67441

800.0	10800.0	0.1570	0.4822	0.3609	1.3166	0.00531	1.0085	0.67975
800.0	10800.0	0.1602	0.4791	0.3608	1.3129	0.00537	1.0086	0.68491
800.0	10800.0	0.1632	0.4760	0.3607	1.3094	0.00543	1.0086	0.68991
800.0	10800.0	0.1663	0.4731	0.3606	1.3060	0.00549	1.0087	0.69474
800.0	10800.0	0.1692	0.4702	0.3605	1.3028	0.00555	1.0087	0.69944
800.0	10800.0	0.1722	0.4674	0.3605	1.2997	0.00561	1.0087	0.70399
800.0	10800.0	0.1750	0.4646	0.3604	1.2967	0.00567	1.0088	0.70843
800.0	10800.0	0.1779	0.4618	0.3603	1.2938	0.00573	1.0088	0.71274
800.0	10800.0	0.1806	0.4591	0.3602	1.2911	0.00579	1.0088	0.71694
800.0	10800.0	0.1834	0.4565	0.3601	1.2884	0.00586	1.0089	0.72104
800.0	10800.0	0.1861	0.4539	0.3601	1.2859	0.00592	1.0089	0.72505
800.0	10800.0	0.1887	0.4513	0.3600	1.2834	0.00598	1.0089	0.72896
800.0	10800.0	0.1914	0.4487	0.3599	1.2810	0.00604	1.0090	0.73278
800.0	10800.0	0.1940	0.4462	0.3598	1.2786	0.00610	1.0090	0.73653
800.0	10800.0	0.1965	0.4437	0.3597	1.2764	0.00617	1.0090	0.74019
800.0	10800.0	0.1991	0.4413	0.3596	1.2742	0.00623	1.0090	0.74379
800.0	10800.0	0.2016	0.4389	0.3595	1.2720	0.00629	1.0091	0.74732
800.0	10800.0	0.2041	0.4365	0.3594	1.2700	0.00635	1.0091	0.75078
800.0	10800.0	0.2066	0.4341	0.3594	1.2679	0.00642	1.0091	0.75418
800.0	10800.0	0.2090	0.4317	0.3593	1.2660	0.00648	1.0092	0.75752
800.0	10800.0	0.2115	0.4294	0.3592	1.2640	0.00655	1.0092	0.76081
800.0	10800.0	0.2139	0.4271	0.3591	1.2621	0.00661	1.0092	0.76404
800.0	10800.0	0.2162	0.4248	0.3590	1.2603	0.00668	1.0092	0.76723
800.0	10800.0	0.2186	0.4225	0.3589	1.2585	0.00674	1.0092	0.77037
800.0	10800.0	0.2210	0.4202	0.3588	1.2568	0.00681	1.0093	0.77346
800.0	10800.0	0.2233	0.4180	0.3587	1.2550	0.00687	1.0093	0.77651
800.0	10800.0	0.2256	0.4157	0.3586	1.2534	0.00694	1.0093	0.77952
800.0	10800.0	0.2279	0.4135	0.3585	1.2517	0.00701	1.0093	0.78250
800.0	10800.0	0.2302	0.4113	0.3584	1.2501	0.00707	1.0094	0.78543
800.0	10800.0	0.2325	0.4091	0.3583	1.2485	0.00714	1.0094	0.78834
800.0	10800.0	0.2348	0.4070	0.3583	1.2469	0.00721	1.0094	0.79121
800.0	10800.0	0.2370	0.4048	0.3582	1.2454	0.00728	1.0094	0.79404
800.0	10800.0	0.2393	0.4027	0.3581	1.2439	0.00734	1.0094	0.79685
800.0	10800.0	0.2415	0.4005	0.3580	1.2424	0.00741	1.0094	0.79963
800.0	10800.0	0.2437	0.3984	0.3579	1.2410	0.00748	1.0095	0.80239
800.0	10800.0	0.2459	0.3963	0.3578	1.2395	0.00755	1.0095	0.80511
800.0	10800.0	0.2481	0.3942	0.3577	1.2381	0.00762	1.0095	0.80782
800.0	10800.0	0.2503	0.3921	0.3576	1.2367	0.00769	1.0095	0.81050
800.0	10800.0	0.2525	0.3900	0.3575	1.2354	0.00776	1.0095	0.81316
800.0	10800.0	0.2547	0.3879	0.3574	1.2340	0.00783	1.0096	0.81580
800.0	10800.0	0.2568	0.3859	0.3573	1.2327	0.00791	1.0096	0.81842
800.0	10800.0	0.2590	0.3838	0.3572	1.2313	0.00798	1.0096	0.82102
800.0	10800.0	0.2611	0.3818	0.3571	1.2300	0.00805	1.0096	0.82360
800.0	10800.0	0.2632	0.3797	0.3570	1.2288	0.00812	1.0096	0.82617
800.0	10800.0	0.2654	0.3777	0.3569	1.2275	0.00820	1.0096	0.82872
800.0	10800.0	0.2675	0.3757	0.3568	1.2262	0.00827	1.0097	0.83125
800.0	10800.0	0.2696	0.3737	0.3567	1.2250	0.00835	1.0097	0.83378
800.0	10800.0	0.2717	0.3717	0.3566	1.2238	0.00842	1.0097	0.83628
800.0	10800.0	0.2738	0.3697	0.3565	1.2226	0.00850	1.0097	0.83878
800.0	10800.0	0.2759	0.3677	0.3564	1.2214	0.00857	1.0097	0.84126
800.0	10800.0	0.2780	0.3657	0.3564	1.2202	0.00865	1.0097	0.84374
800.0	10800.0	0.2800	0.3637	0.3563	1.2190	0.00872	1.0098	0.84620
800.0	10800.0	0.2821	0.3617	0.3562	1.2178	0.00880	1.0098	0.84866
800.0	10800.0	0.2842	0.3598	0.3561	1.2167	0.00888	1.0098	0.85110

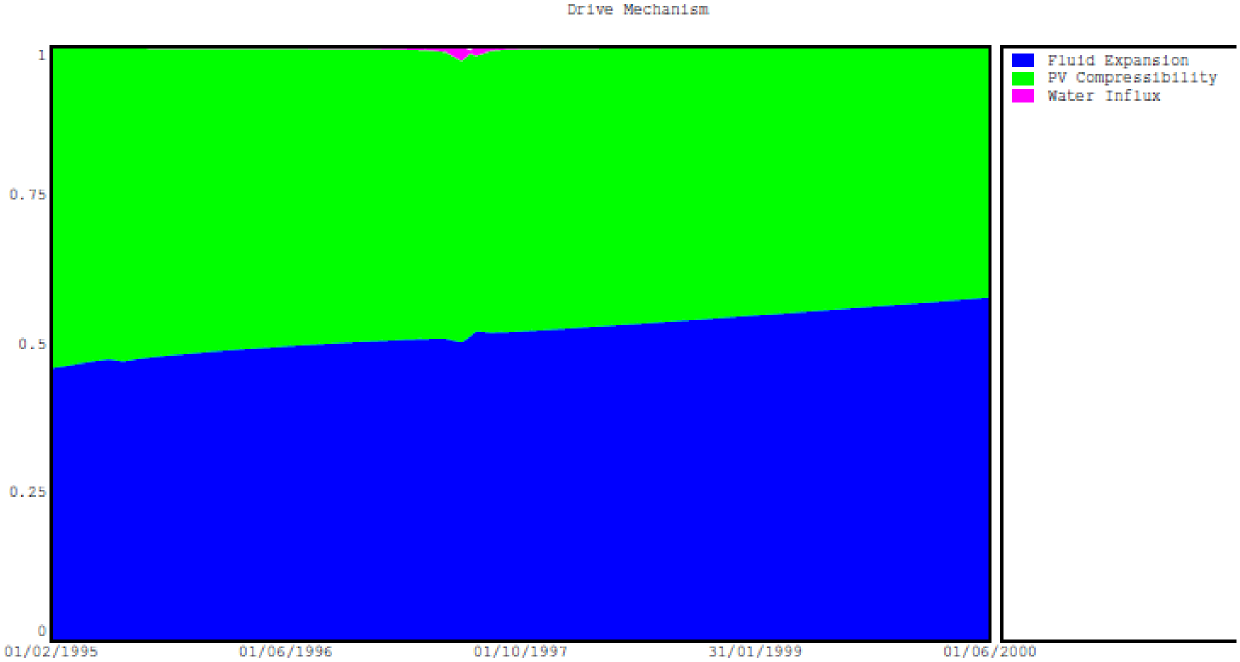
800.0	10800.0	0.2862	0.3578	0.3560	1.2155	0.00896	1.0098	0.85354
800.0	10800.0	0.2883	0.3558	0.3559	1.2144	0.00904	1.0098	0.85597
800.0	10800.0	0.2903	0.3539	0.3558	1.2133	0.00912	1.0098	0.85839
800.0	10800.0	0.2924	0.3519	0.3557	1.2121	0.00920	1.0098	0.86080
800.0	10800.0	0.2944	0.3500	0.3556	1.2110	0.00928	1.0099	0.86321
800.0	10800.0	0.2964	0.3481	0.3555	1.2099	0.00936	1.0099	0.86562
800.0	10800.0	0.2985	0.3461	0.3554	1.2088	0.00944	1.0099	0.86801
800.0	10800.0	0.3005	0.3442	0.3553	1.2078	0.00952	1.0099	0.87041
800.0	10800.0	0.3025	0.3423	0.3552	1.2067	0.00961	1.0099	0.87280
800.0	10800.0	0.3045	0.3404	0.3551	1.2056	0.00969	1.0099	0.87518
800.0	10800.0	0.3065	0.3385	0.3550	1.2045	0.00977	1.0099	0.87757
800.0	10800.0	0.3085	0.3366	0.3549	1.2035	0.00986	1.0100	0.87995
800.0	10800.0	0.3105	0.3347	0.3548	1.2024	0.00994	1.0100	0.88232
800.0	10800.0	0.3125	0.3328	0.3547	1.2014	0.01003	1.0100	0.88470
800.0	10800.0	0.3145	0.3309	0.3546	1.2004	0.01012	1.0100	0.88707
800.0	10800.0	0.3165	0.3290	0.3545	1.1993	0.01020	1.0100	0.88945
800.0	10800.0	0.3185	0.3271	0.3544	1.1983	0.01029	1.0100	0.89182
800.0	10800.0	0.3204	0.3252	0.3543	1.1973	0.01038	1.0100	0.89419
800.0	10800.0	0.3224	0.3234	0.3542	1.1963	0.01047	1.0101	0.89656
800.0	10800.0	0.3244	0.3215	0.3541	1.1953	0.01056	1.0101	0.89893
800.0	10800.0	0.3264	0.3196	0.3540	1.1943	0.01065	1.0101	0.90130
800.0	10800.0	0.3283	0.3178	0.3539	1.1933	0.01074	1.0101	0.90368
800.0	10800.0	0.3303	0.3159	0.3538	1.1923	0.01083	1.0101	0.90605
800.0	10800.0	0.3322	0.3141	0.3537	1.1913	0.01093	1.0101	0.90842
800.0	10800.0	0.3342	0.3122	0.3536	1.1903	0.01102	1.0101	0.91080
800.0	10800.0	0.3361	0.3104	0.3535	1.1893	0.01112	1.0102	0.91318
800.0	10800.0	0.3381	0.3085	0.3534	1.1883	0.01121	1.0102	0.91556
800.0	10800.0	0.3400	0.3067	0.3533	1.1874	0.01131	1.0102	0.91794
800.0	10800.0	0.3419	0.3048	0.3532	1.1864	0.01140	1.0102	0.92033
800.0	10800.0	0.3439	0.3030	0.3531	1.1854	0.01150	1.0102	0.92272
800.0	10800.0	0.3458	0.3012	0.3530	1.1845	0.01160	1.0102	0.92511
800.0	10800.0	0.3477	0.2994	0.3529	1.1835	0.01170	1.0102	0.92750
800.0	10800.0	0.3496	0.2975	0.3528	1.1825	0.01180	1.0102	0.92990
800.0	10800.0	0.3516	0.2957	0.3527	1.1816	0.01190	1.0103	0.93230
800.0	10800.0	0.3516	0.2956	0.3527	1.1815	0.01191	1.0103	0.93241

Gas Viscosity (centipoise)	Water Viscosity (centipoise)	Oil Density (lb/ft3)	Gas Density (lb/ft3)	Water Cut (percent)	Solution GOR (scf/STB)	Producing GOR (scf/STB)	Cum GOR (scf/STB)	GLR (scf/STB)
0.04669	0.60539	41.049	23.222		990			
0.04525	0.60539	40.951	22.851	7.41	990	1000	1000	926
0.04383	0.60539	40.850	22.472	7.41	990	1000	1000	926
0.04242	0.60539	40.746	22.083	7.41	990	1000	1000	926
0.04035	0.60539	41.066	21.484	7.41	941	1000	1000	926
0.03834	0.60539	41.729	20.863	7.41	861	1000	1000	926
0.03695	0.60539	42.160	20.411	7.41	813	1000	1000	926
0.03582	0.60539	42.494	20.029	7.41	776	1000	1000	926
0.03484	0.60539	42.769	19.689	7.41	747	1000	1000	926
0.03398	0.60539	43.004	19.376	7.41	722	1000	1000	926
0.03319	0.60539	43.210	19.085	7.41	701	1000	1000	926
0.03247	0.60539	43.392	18.809	7.41	682	1000	1000	926

0.03180	0.60539	43.557	18.547	7.41	666	1000	1000	926
0.03117	0.60539	43.706	18.295	7.41	651	1000	1000	926
0.03058	0.60539	43.843	18.053	7.41	638	1000	1000	926
0.03003	0.60539	43.968	17.820	7.41	626	1000	1000	926
0.02950	0.60539	44.085	17.594	7.41	614	1000	1000	926
0.02900	0.60539	44.193	17.375	7.41	604	1000	1000	926
0.02853	0.60539	44.294	17.162	7.41	594	1000	1000	926
0.02807	0.60539	44.389	16.954	7.41	585	1000	1000	926
0.02764	0.60539	44.478	16.752	7.41	577	1000	1000	926
0.02722	0.60539	44.562	16.554	7.41	569	1000	1000	926
0.02682	0.60539	44.641	16.361	7.41	562	1000	1000	926
0.02644	0.60539	44.716	16.173	7.41	555	1000	1000	926
0.02607	0.60539	44.788	15.988	7.41	548	1000	1000	926
0.02572	0.60539	44.856	15.808	7.41	542	1000	1000	926
0.02538	0.60539	44.921	15.631	7.41	536	1000	1000	926
0.02505	0.60539	44.984	15.457	7.41	530	1000	1000	926
0.02473	0.60539	45.043	15.287	7.41	525	1000	1000	926
0.02443	0.60539	45.101	15.121	7.41	520	1000	1000	926
0.02413	0.60539	45.156	14.957	7.41	515	1000	1000	926
0.02385	0.60539	45.209	14.796	7.41	510	1000	1000	926
0.02357	0.60539	45.260	14.639	7.41	505	1000	1000	926
0.02330	0.60539	45.309	14.484	7.41	501	1000	1000	926
0.02304	0.60539	45.357	14.331	7.41	497	1000	1000	926
0.02279	0.60539	45.403	14.182	7.41	492	1000	1000	926
0.02255	0.60539	45.448	14.035	7.41	488	1000	1000	926
0.02231	0.60539	45.491	13.890	7.41	485	1000	1000	926
0.02208	0.60539	45.533	13.748	7.41	481	1000	1000	926
0.02186	0.60539	45.574	13.608	7.41	477	1000	1000	926
0.02164	0.60539	45.614	13.470	7.41	474	1000	1000	926
0.02143	0.60539	45.653	13.334	7.41	470	1000	1000	926
0.02123	0.60539	45.690	13.201	7.41	467	1000	1000	926
0.02103	0.60539	45.727	13.069	7.41	464	1000	1000	926
0.02084	0.60539	45.763	12.940	7.41	460	1000	1000	926
0.02065	0.60539	45.798	12.812	7.41	457	1000	1000	926
0.02047	0.60539	45.832	12.686	7.41	454	1000	1000	926
0.02029	0.60539	45.866	12.563	7.41	451	1000	1000	926
0.02012	0.60539	45.899	12.441	7.41	448	1000	1000	926
0.01995	0.60539	45.931	12.320	7.41	446	1000	1000	926
0.01978	0.60539	45.963	12.202	7.41	443	1000	1000	926
0.01962	0.60539	45.994	12.085	7.41	440	1000	1000	926
0.01946	0.60539	46.024	11.969	7.41	437	1000	1000	926
0.01931	0.60539	46.054	11.856	7.41	435	1000	1000	926
0.01916	0.60539	46.083	11.743	7.41	432	1000	1000	926
0.01902	0.60539	46.112	11.633	7.41	430	1000	1000	926
0.01887	0.60539	46.140	11.523	7.41	427	1000	1000	926
0.01873	0.60539	46.168	11.416	7.41	425	1000	1000	926
0.01860	0.60539	46.195	11.309	7.41	422	1000	1000	926
0.01847	0.60539	46.222	11.204	7.41	420	1000	1000	926
0.01834	0.60539	46.249	11.100	7.41	418	1000	1000	926
0.01821	0.60539	46.275	10.998	7.41	415	1000	1000	926
0.01809	0.60539	46.301	10.897	7.41	413	1000	1000	926
0.01796	0.60539	46.327	10.797	7.41	411	1000	1000	926
0.01785	0.60539	46.352	10.699	7.41	409	1000	1000	926
0.01773	0.60539	46.377	10.601	7.41	407	1000	1000	926

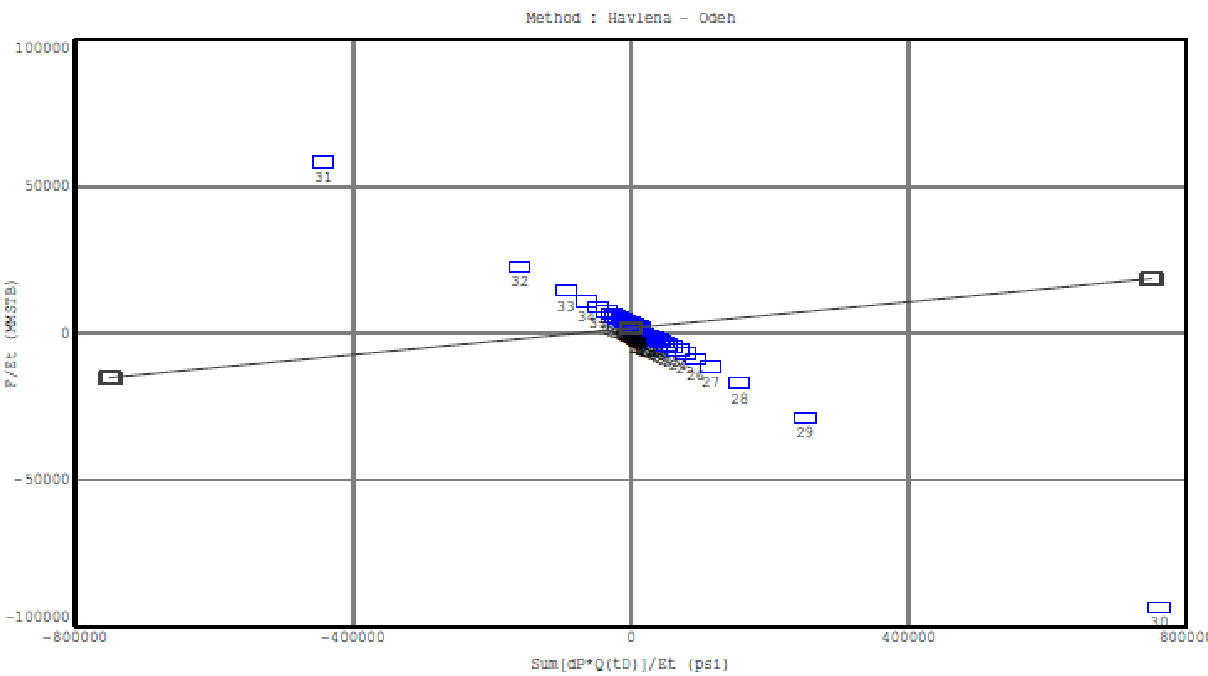
0.01762	0.60539	46.401	10.505	7.41	404	1000	1000	926
0.01750	0.60539	46.425	10.410	7.41	402	1000	1000	926
0.01740	0.60539	46.449	10.316	7.41	400	1000	1000	926
0.01729	0.60539	46.473	10.223	7.41	398	1000	1000	926
0.01718	0.60539	46.497	10.132	7.41	396	1000	1000	926
0.01708	0.60539	46.520	10.041	7.41	394	1000	1000	926
0.01698	0.60539	46.543	9.952	7.41	392	1000	1000	926
0.01688	0.60539	46.566	9.863	7.41	390	1000	1000	926
0.01679	0.60539	46.588	9.775	7.41	388	1000	1000	926
0.01669	0.60539	46.611	9.689	7.41	386	1000	1000	926
0.01660	0.60539	46.633	9.603	7.41	384	1000	1000	926
0.01651	0.60539	46.655	9.519	7.41	382	1000	1000	926
0.01642	0.60539	46.677	9.435	7.41	381	1000	1000	926
0.01633	0.60539	46.698	9.352	7.41	379	1000	1000	926
0.01625	0.60539	46.720	9.270	7.41	377	1000	1000	926
0.01616	0.60539	46.741	9.189	7.41	375	1000	1000	926
0.01608	0.60539	46.762	9.109	7.41	373	1000	1000	926
0.01600	0.60539	46.783	9.030	7.41	371	1000	1000	926
0.01592	0.60539	46.804	8.951	7.41	370	1000	1000	926
0.01584	0.60539	46.824	8.874	7.41	368	1000	1000	926
0.01576	0.60539	46.845	8.797	7.41	366	1000	1000	926
0.01569	0.60539	46.865	8.721	7.41	364	1000	1000	926
0.01561	0.60539	46.886	8.645	7.41	363	1000	1000	926
0.01554	0.60539	46.906	8.571	7.41	361	1000	1000	926
0.01547	0.60539	46.926	8.497	7.41	359	1000	1000	926
0.01540	0.60539	46.946	8.424	7.41	357	1000	1000	926
0.01533	0.60539	46.966	8.352	7.41	356	1000	1000	926
0.01526	0.60539	46.985	8.280	7.41	354	1000	1000	926
0.01519	0.60539	47.005	8.209	7.41	352	1000	1000	926
0.01513	0.60539	47.025	8.139	7.41	350	1000	1000	926
0.01506	0.60539	47.044	8.069	7.41	349	1000	1000	926
0.01500	0.60539	47.063	8.000	7.41	347	1000	1000	926
0.01494	0.60539	47.083	7.932	7.41	345	1000	1000	926
0.01487	0.60539	47.102	7.864	7.41	344	1000	1000	926
0.01481	0.60539	47.121	7.797	7.41	342	1000	1000	926
0.01475	0.60539	47.140	7.731	7.41	341	1000	1000	926
0.01469	0.60539	47.159	7.665	7.41	339	1000	1000	926
0.01464	0.60539	47.178	7.600	7.41	337	1000	1000	926
0.01458	0.60539	47.197	7.535	7.41	336	1000	1000	926
0.01452	0.60539	47.216	7.471	7.41	334	1000	1000	926
0.01447	0.60539	47.234	7.408	7.41	332	1000	1000	926
0.01441	0.60539	47.253	7.345	7.41	331	1000	1000	926
0.01436	0.60539	47.271	7.283	7.41	329	1000	1000	926
0.01431	0.60539	47.290	7.221	7.41	328	1000	1000	926
0.01425	0.60539	47.308	7.159	7.41	326	1000	1000	926
0.01420	0.60539	47.327	7.099	7.41	324	1000	1000	926
0.01415	0.60539	47.345	7.038	7.41	323	1000	1000	926
0.01410	0.60539	47.363	6.978	7.41	321	1000	1000	926
0.01410	0.60539	47.364	6.976	7.41	321	1000	1000	926

Appendix II: Drive mechanism after CO_2 EOR



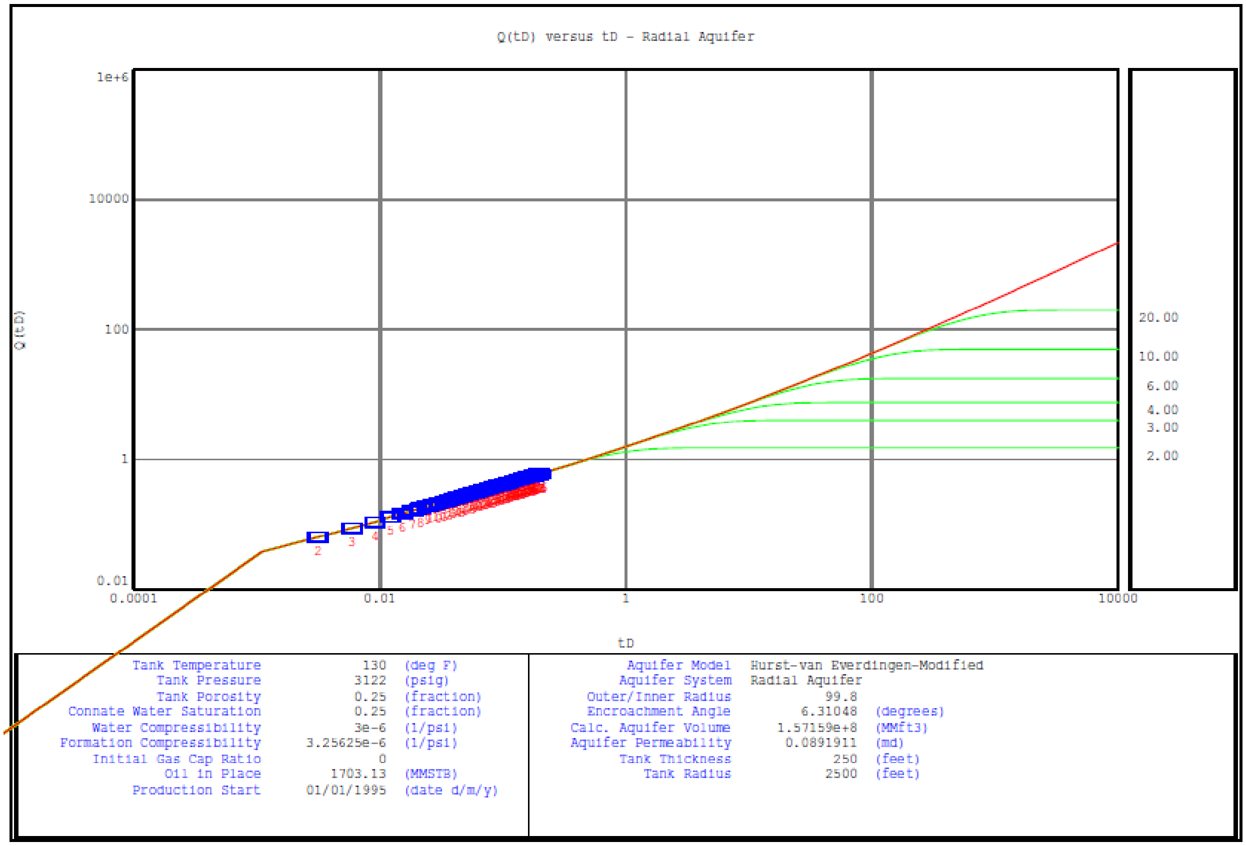
Graph 18: Drive mechanism

Appendix III: Simulation plot after regression



Graph 19: After regression

Appendix IV: Radial aquifer plot Q(tD) vs tD after CO_2 EOR



Graph 20: Q(tD) vs tD

Appendix V: Tank production prediction after CO_2 EOR

Table 19: Highlights of production prediction (1995 to 2000)

Time	Tank Pressure	Oil recovery factor	Avg.oil rate	Avg. gas rate	Avg. water rate
(Date)	(psig)	(%)	(STB/day)	(MMscf/day)	(STB/day)
1/1/1995	3122	0			
1/2/1995	2862.64	0.47	11491	5.7455	0
1/3/1995	2773.31	0.78	8211.8	4.1059	0
1/4/1995	2627.65	1.24	10995.7	5.4979	0
1/5/1995	2522.37	1.67	10746.7	5.3733	0
1/6/1995	2433.29	2.1	10550.6	5.2754	0
1/7/1995	2559.86	2.1	0	0	0
1/8/1995	2433.34	2.53	10242.9	5.1215	0

01-09-95	2350.12	2.94	10040.3	5.0199	0
01-10-95	2285.25	3.34	9882	4.9413	0
01-11-95	2228.21	3.74	9749	4.8745	0
01-12-95	2179.97	4.12	9629	4.8143	0
01-01-96	2129.72	4.53	9854.5	4.9274	0
01-02-96	2085.65	4.93	9748.4	4.8739	0
01-03-96	2048.52	5.31	9652.1	4.8262	0
01-04-96	2010.28	5.7	9565.5	4.7826	0
01-05-96	1976.53	6.08	9481	4.7407	0
01-06-96	1946.26	6.47	9334.8	4.6674	0
01-07-96	1940.69	6.84	9260.3	4.6303	0
01-08-96	1934.18	7.22	9189.7	4.5948	0
01-09-96	1927.58	7.59	9119	4.5594	0
01-10-96	1920.76	7.96	9050.3	4.5253	0
01-11-96	1913.44	8.33	8984.2	4.4919	0
01-12-96	1906.27	8.68	8918.3	4.4593	0
01-01-97	1899.68	9.04	8555.5	4.2774	0
01-02-97	1892.96	9.39	8495.8	4.2481	0
01-03-97	1886.82	9.7	8437.1	4.2186	0
01-04-97	1879.95	10.05	8381.3	4.1906	0
01-05-97	1873.25	10.38	8321.3	4.1607	0
01-06-97	1866.29	10.73	8262.9	4.1313	0
01-07-97	1857.98	11.05	8000	4	964.5
01-08-97	1849.26	11.38	8000	4	988.7
01-09-97	1840.43	11.71	8000	4	1013.4
01-10-97	1831.77	12.03	8000	4	1037.7
01-11-97	1822.7	12.36	8000	4	1061.5
01-12-97	1813.82	12.68	8000	4	1085.7
01-01-98	1804.55	13.01	8000	4	1109.2
01-02-98	1795.19	13.34	7998.4	4	1133.2
01-03-98	1786.66	13.64	8000	4	1156.4
01-04-98	1777.16	13.97	8000	4	1178.4
01-05-98	1767.9	14.29	8000	4	1201.8
01-06-98	1758.28	14.62	8003.2	4	1224.6
01-07-98	1748.93	14.94	8000	4	1247.7
01-08-98	1739.23	15.27	7996.8	4	1270.3
01-09-98	1729.5	15.6	8000	4	1293.3
01-10-98	1720.05	15.92	8000	4	1316
01-11-98	1710.26	16.25	8003.2	4	1338.3
01-12-98	1700.77	16.57	7996.7	4	1360.7
01-01-99	1690.95	16.9	8000	4	1382.6
1/2/1999	1681.13	17.23	8000	4	1405
1/3/1999	1672.25	17.53	8000	4	1426.7
1/4/1999	1662.42	17.86	8000	4	1447.2
1/5/1999	1652.9	18.18	8000	4	1469

01-06-99	1643.08	18.51	8000	4	1490.3
01-07-99	1633.58	18.83	8003.3	4	1511.9
01-08-99	1623.77	19.16	7996.8	4	1533
01-09-99	1613.98	19.49	8000	4	1554.5
01-10-99	1604.52	19.81	8000	4	1575.7
01-11-99	1594.76	20.14	8003.2	4	1596.8
01-12-99	1585.34	20.46	7996.7	4	1617.3
01-01-00	1575.62	20.79	8000	4	1638.1
01-02-00	1565.92	21.13	8000	4	1659
01-03-00	1556.87	21.43	8000	4	1679.3
01-04-00	1547.22	21.77	8000	4	1699.4
01-05-00	1537.91	22.09	8000	4	1719.3
01-06-00	1528.32	22.42	8000	4	1739.7

Table 20: Production prediction run simulation after CO_2 EOR

. Stream : Prediction .

Time (date d/m/y)	Tank Pressure (psig)	Oil Recovery Factor (percent)	Oil Rate (STB/day)	Gas Rate (MMscf/day)	Water Rate (STB/day)	Liquid Rate (STB/day)	Gas Inj Rate (MMscf/day)	Avg.Oil Rate (STB/day)
01/01/1995	3122.00	0.00	11491.0	5.7455	0.0	11491.0	0.0000	
01/02/1995	2862.64	0.47	8211.8	4.1059	0.0	8211.8	0.0000	11491.0
01/03/1995	2773.31	0.78	10995.7	5.4979	0.0	10995.7	0.0000	8211.8
01/04/1995	2627.65	1.24	10746.7	5.3733	0.0	10746.7	0.0000	10995.7
01/05/1995	2522.37	1.67	10550.6	5.2754	0.0	10550.6	0.0000	10746.7
01/06/1995	2433.29	2.10	0.0	0.0000	0.0	0.0	0.0000	10550.6
01/07/1995	2559.86	2.10	10242.9	5.1215	0.0	10242.9	0.0000	0.0
01/08/1995	2433.34	2.53	10040.3	5.0199	0.0	10040.3	0.0000	10242.9
01/09/1995	2350.12	2.94	9882.0	4.9413	0.0	9882.0	0.0000	10040.3
01/10/1995	2285.25	3.34	9749.0	4.8745	0.0	9749.0	0.0000	9882.0
01/11/1995	2228.21	3.74	9629.0	4.8143	0.0	9629.0	0.0000	9749.0
01/12/1995	2179.97	4.12	9854.5	4.9274	0.0	9854.5	0.0000	9629.0
01/01/1996	2129.72	4.53	9748.4	4.8739	0.0	9748.4	0.0000	9854.5
01/02/1996	2085.65	4.93	9652.1	4.8262	0.0	9652.1	0.0000	9748.4
01/03/1996	2048.52	5.31	9565.5	4.7826	0.0	9565.5	0.0000	9652.1
01/04/1996	2010.28	5.70	9481.0	4.7407	0.0	9481.0	0.0000	9565.5
01/05/1996	1976.53	6.08	9334.8	4.6674	0.0	9334.8	0.0000	9481.0
01/06/1996	1946.26	6.47	9260.3	4.6303	0.0	9260.3	0.0000	9334.8
01/07/1996	1940.69	6.84	9189.7	4.5948	0.0	9189.7	0.0000	9260.3
01/08/1996	1934.18	7.22	9119.0	4.5594	0.0	9119.0	0.0000	9189.7
01/09/1996	1927.58	7.59	9050.3	4.5253	0.0	9050.3	0.0000	9119.0
01/10/1996	1920.76	7.96	8984.2	4.4919	0.0	8984.2	0.0000	9050.3
01/11/1996	1913.44	8.33	8918.3	4.4593	0.0	8918.3	0.0000	8984.2
01/12/1996	1906.27	8.68	8555.5	4.2774	0.0	8555.5	0.0000	8918.3
01/01/1997	1899.68	9.04	8495.8	4.2481	0.0	8495.8	0.0000	8555.5
01/02/1997	1892.96	9.39	8437.1	4.2186	0.0	8437.1	0.0000	8495.8
01/03/1997	1886.82	9.70	8381.3	4.1906	0.0	8381.3	0.0000	8437.1
01/04/1997	1879.95	10.05	8321.3	4.1607	0.0	8321.3	0.0000	8381.3
01/05/1997	1873.25	10.38	8262.9	4.1313	0.0	8262.9	0.0000	8321.3
01/06/1997	1866.29	10.73	8000.0	4.0000	964.5	8964.5	0.0000	8262.9
01/07/1997	1857.98	11.05	8000.0	4.0000	988.7	8988.7	0.0000	8000.0
01/08/1997	1849.26	11.38	8000.0	4.0000	1013.4	9013.4	0.0000	8000.0
01/09/1997	1840.43	11.71	8000.0	4.0000	1037.7	9037.7	0.0000	8000.0
01/10/1997	1831.77	12.03	8000.0	4.0000	1061.5	9061.5	0.0000	8000.0
01/11/1997	1822.70	12.36	8000.0	4.0000	1085.7	9085.7	0.0000	8000.0
01/12/1997	1813.82	12.68	8000.0	4.0000	1109.2	9109.2	0.0000	8000.0
01/01/1998	1804.55	13.01	7998.4	4.0000	1133.2	9131.5	0.0000	8000.0
01/02/1998	1795.19	13.34	8000.0	4.0000	1156.4	9156.4	0.0000	7998.4
01/03/1998	1786.66	13.64	8000.0	4.0000	1178.4	9178.4	0.0000	8000.0
01/04/1998	1777.16	13.97	8000.0	4.0000	1201.8	9201.8	0.0000	8000.0

01/05/1998	1767.90	14.29	8003.2	4.0000	1224.6	9227.9	0.0000	8000.0
01/06/1998	1758.28	14.62	8000.0	4.0000	1247.7	9247.7	0.0000	8003.2
01/07/1998	1748.93	14.94	7996.8	4.0000	1270.3	9267.1	0.0000	8000.0
01/08/1998	1739.23	15.27	8000.0	4.0000	1293.3	9293.3	0.0000	7996.8
01/09/1998	1729.50	15.60	8000.0	4.0000	1316.0	9316.0	0.0000	8000.0
01/10/1998	1720.05	15.92	8003.2	4.0000	1338.3	9341.5	0.0000	8000.0
01/11/1998	1710.26	16.25	7996.7	4.0000	1360.7	9357.3	0.0000	8003.2
01/12/1998	1700.77	16.57	8000.0	4.0000	1382.6	9382.6	0.0000	7996.7
01/01/1999	1690.95	16.90	8000.0	4.0000	1405.0	9405.0	0.0000	8000.0
01/02/1999	1681.13	17.23	8000.0	4.0000	1426.7	9426.7	0.0000	8000.0
01/03/1999	1672.25	17.53	8000.0	4.0000	1447.2	9447.2	0.0000	8000.0
01/04/1999	1662.42	17.86	8000.0	4.0000	1469.0	9469.0	0.0000	8000.0
01/05/1999	1652.90	18.18	8000.0	4.0000	1490.3	9490.3	0.0000	8000.0
01/06/1999	1643.08	18.51	8003.3	4.0000	1511.9	9515.3	0.0000	8000.0
01/07/1999	1633.58	18.83	7996.8	4.0000	1533.0	9529.8	0.0000	8003.3
01/08/1999	1623.77	19.16	8000.0	4.0000	1554.5	9554.5	0.0000	7996.8
01/09/1999	1613.98	19.49	8000.0	4.0000	1575.7	9575.7	0.0000	8000.0
01/10/1999	1604.52	19.81	8003.2	4.0000	1596.8	9600.0	0.0000	8000.0
01/11/1999	1594.76	20.14	7996.7	4.0000	1617.3	9614.0	0.0000	8003.2
01/12/1999	1585.34	20.46	8000.0	4.0000	1638.1	9638.1	0.0000	7996.7
01/01/2000	1575.62	20.79	8000.0	4.0000	1659.0	9659.0	0.0000	8000.0
01/02/2000	1565.92	21.13	8000.0	4.0000	1679.3	9679.3	0.0000	8000.0
01/03/2000	1556.87	21.43	8000.0	4.0000	1699.4	9699.4	0.0000	8000.0
01/04/2000	1547.22	21.77	8000.0	4.0000	1719.3	9719.3	0.0000	8000.0
01/05/2000	1537.91	22.09	8000.0	4.0000	1739.7	9739.7	0.0000	8000.0
01/06/2000	1528.32	22.42	0.0	0.0000	0.0	0.0	0.0000	8000.0

Avg.Gas Rate (MMscf/day)	Avg.Water Rate (STB/day)	Avg.Liq Rate (STB/day)	Avg.Gas Inj Rate (MMscf/day)	Gas Saturation (fraction)	Oil Saturation (fraction)	Water Saturation (fraction)	Man Pres (psig)	Gas Inj Man Pres (psig)
				0.00000	0.75000	0.25000		
5.7455	0.0	11491.0	0.0000	0.00000	0.74827	0.25173		
4.1059	0.0	8211.8	0.0000	0.00000	0.74665	0.25335		
5.4979	0.0	10995.7	0.0000	0.00000	0.74440	0.25560		
5.3733	0.0	10746.7	0.0000	0.00000	0.74207	0.25793		
5.2754	0.0	10550.6	0.0000	0.00000	0.73959	0.26041		
0.0000	0.0	0.0	0.0000	0.00000	0.73845	0.26155		
5.1215	0.0	10242.9	0.0000	0.00000	0.73639	0.26361		
5.0199	0.0	10040.3	0.0000	0.00000	0.73404	0.26596		
4.9413	0.0	9882.0	0.0000	0.00000	0.73170	0.26830		
4.8745	0.0	9749.0	0.0000	0.00000	0.72923	0.27077		
4.8143	0.0	9629.0	0.0000	0.00000	0.72683	0.27317		
4.9274	0.0	9854.5	0.0000	0.00000	0.72429	0.27571		
4.8739	0.0	9748.4	0.0000	0.00000	0.72174	0.27826		
4.8262	0.0	9652.1	0.0000	0.00000	0.71933	0.28067		
4.7826	0.0	9565.5	0.0000	0.00000	0.71679	0.28321		
4.7407	0.0	9481.0	0.0000	0.00000	0.71432	0.28568		
4.6674	0.0	9334.8	0.0000	0.00000	0.71173	0.28822		
4.6303	0.0	9260.3	0.0000	0.00105	0.70844	0.29052		
4.5948	0.0	9189.7	0.0000	0.00221	0.70499	0.29280		
4.5594	0.0	9119.0	0.0000	0.00339	0.70157	0.29505		

4.5253	0.0	9050.3	0.0000	0.00460	0.69824	0.29715
4.4919	0.0	8984.2	0.0000	0.00591	0.69481	0.29928
4.4593	0.0	8918.3	0.0000	0.00718	0.69151	0.30130
4.2774	0.0	8555.5	0.0000	0.00836	0.68829	0.30336
4.2481	0.0	8495.8	0.0000	0.00955	0.68508	0.30537
4.2186	0.0	8437.1	0.0000	0.01064	0.68219	0.30717
4.1906	0.0	8381.3	0.0000	0.01186	0.67901	0.30913
4.1607	0.0	8321.3	0.0000	0.01305	0.67596	0.31099
4.1313	0.0	8262.9	0.0000	0.01428	0.67282	0.31289
4.0000	964.5	8964.5	0.0000	0.01577	0.66974	0.31448
4.0000	988.7	8988.7	0.0000	0.01734	0.66656	0.31610
4.0000	1013.4	9013.4	0.0000	0.01893	0.66337	0.31769
4.0000	1037.7	9037.7	0.0000	0.02050	0.66029	0.31922
4.0000	1061.5	9061.5	0.0000	0.02214	0.65710	0.32076
4.0000	1085.7	9085.7	0.0000	0.02376	0.65401	0.32224
4.0000	1109.2	9109.2	0.0000	0.02545	0.65081	0.32374
4.0000	1133.2	9131.5	0.0000	0.02716	0.64762	0.32522
4.0000	1156.4	9156.4	0.0000	0.02873	0.64474	0.32654
4.0000	1178.4	9178.4	0.0000	0.03048	0.64155	0.32797
4.0000	1201.8	9201.8	0.0000	0.03219	0.63847	0.32935
4.0000	1224.6	9227.9	0.0000	0.03398	0.63528	0.33074
4.0000	1247.7	9247.7	0.0000	0.03572	0.63220	0.33207
4.0000	1270.3	9267.1	0.0000	0.03754	0.62903	0.33343
4.0000	1293.3	9293.3	0.0000	0.03937	0.62586	0.33477
4.0000	1316.0	9316.0	0.0000	0.04116	0.62280	0.33604
4.0000	1338.3	9341.5	0.0000	0.04302	0.61964	0.33734
4.0000	1360.7	9357.3	0.0000	0.04483	0.61659	0.33858
4.0000	1382.6	9382.6	0.0000	0.04671	0.61344	0.33985
4.0000	1405.0	9405.0	0.0000	0.04860	0.61030	0.34109
4.0000	1426.7	9426.7	0.0000	0.05032	0.60748	0.34220
4.0000	1447.2	9447.2	0.0000	0.05223	0.60435	0.34341
4.0000	1469.0	9469.0	0.0000	0.05409	0.60133	0.34457
4.0000	1490.3	9490.3	0.0000	0.05602	0.59822	0.34575
4.0000	1511.9	9515.3	0.0000	0.05790	0.59522	0.34688
4.0000	1533.0	9529.8	0.0000	0.05985	0.59213	0.34802
4.0000	1554.5	9554.5	0.0000	0.06180	0.58904	0.34915
4.0000	1575.7	9575.7	0.0000	0.06370	0.58607	0.35023
4.0000	1596.8	9600.0	0.0000	0.06567	0.58300	0.35133
4.0000	1617.3	9614.0	0.0000	0.06758	0.58003	0.35238
4.0000	1638.1	9638.1	0.0000	0.06956	0.57698	0.35345
4.0000	1659.0	9659.0	0.0000	0.07155	0.57394	0.35451
4.0000	1679.3	9679.3	0.0000	0.07342	0.57110	0.35548
4.0000	1699.4	9699.4	0.0000	0.07542	0.56807	0.35650
4.0000	1719.3	9719.3	0.0000	0.07736	0.56515	0.35748
4.0000	1739.7	9739.7	0.0000	0.07937	0.56215	0.35848

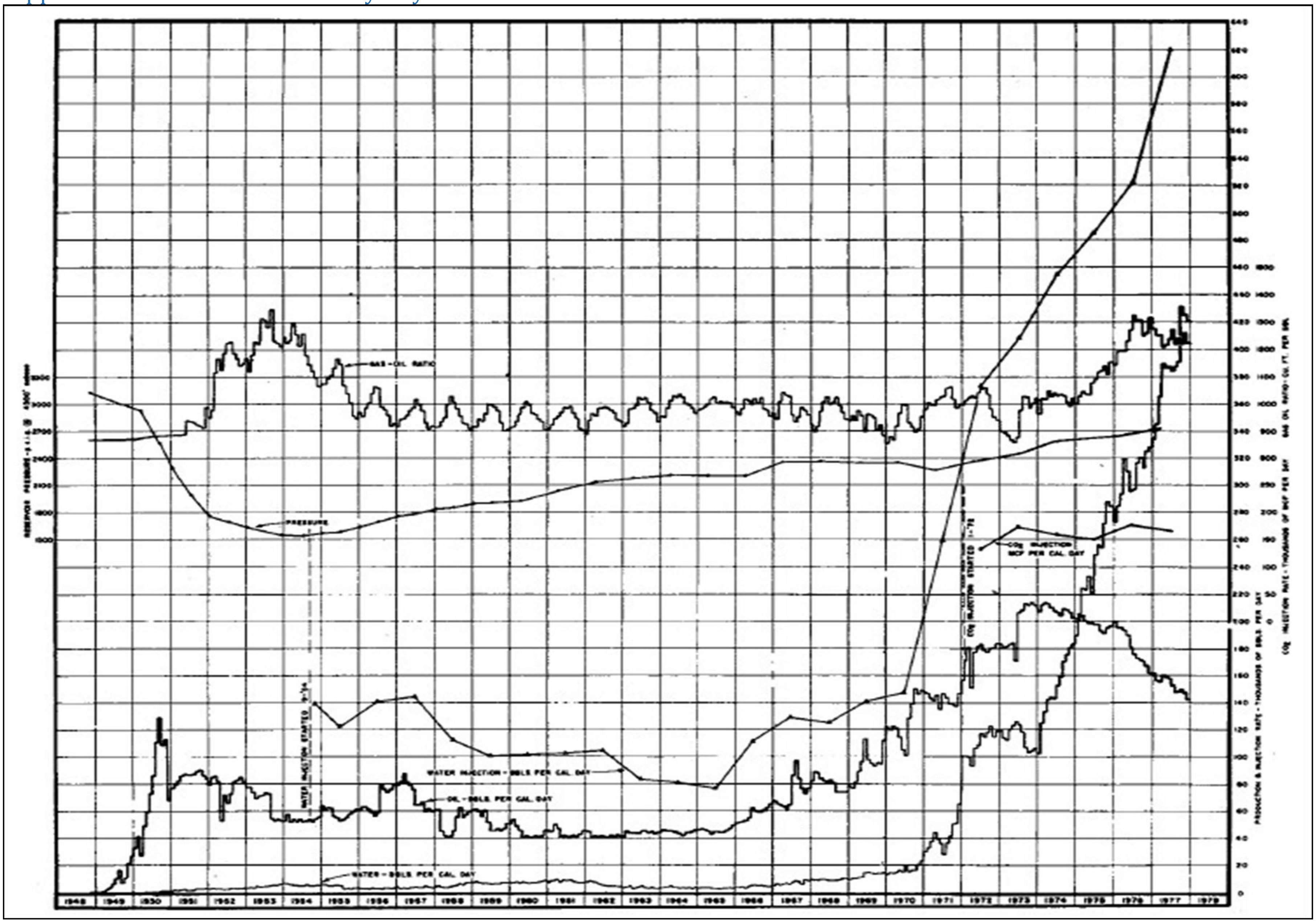
Oil FVF (RB/STB)	Gas FVF (ft3/scf)	Water FVF (RB/STB)	Oil Viscosity (centipoise)	Gas Viscosity (centipoise)	Water Viscosity (centipoise)	Oil Density (lb/ft3)	Gas Density (lb/ft3)	Oil Rel. Perm. (fraction)
1.2422	0.00401	1.0034	0.93083	0.02636	0.56857	46.083	15.192	0.8
1.2442	0.00427	1.0042	0.90182	0.02469	0.56857	46.009	14.285	0.776

1.2450	0.00437	1.0044	0.89234	0.02410	0.56857	45.980	13.944	0.754
1.2463	0.00457	1.0049	0.87747	0.02312	0.56857	45.930	13.356	0.725
1.2474	0.00473	1.0052	0.86719	0.02241	0.56857	45.889	12.903	0.695
1.2484	0.00488	1.0055	0.85880	0.02180	0.56857	45.852	12.503	0.665
1.2470	0.00467	1.0051	0.87080	0.02266	0.56857	45.904	13.067	0.652
1.2484	0.00488	1.0055	0.85880	0.02180	0.56857	45.852	12.503	0.628
1.2494	0.00503	1.0057	0.85124	0.02123	0.56857	45.816	12.113	0.602
1.2503	0.00517	1.0059	0.84552	0.02079	0.56857	45.785	11.799	0.577
1.2511	0.00529	1.0061	0.84063	0.02040	0.56857	45.757	11.516	0.552
1.2517	0.00541	1.0062	0.83660	0.02007	0.56857	45.732	11.271	0.528
1.2525	0.00554	1.0064	0.83250	0.01973	0.56857	45.704	11.010	0.504
1.2532	0.00566	1.0065	0.82899	0.01943	0.56857	45.679	10.778	0.481
1.2538	0.00576	1.0066	0.82610	0.01918	0.56857	45.657	10.579	0.46
1.2544	0.00588	1.0067	0.82318	0.01892	0.56857	45.634	10.371	0.439
1.2550	0.00599	1.0068	0.82065	0.01870	0.56857	45.613	10.186	0.419
1.2555	0.00609	1.0069	0.81855	0.01850	0.56857	45.594	10.018	0.399
1.2546	0.00610	1.0069	0.82015	0.01846	0.56857	45.612	9.987	0.375
1.2536	0.00613	1.0070	0.82203	0.01842	0.56857	45.632	9.951	0.351
1.2526	0.00615	1.0070	0.82394	0.01838	0.56857	45.653	9.914	0.329
1.2515	0.00617	1.0070	0.82592	0.01833	0.56857	45.674	9.876	0.309
1.2504	0.00620	1.0070	0.82806	0.01829	0.56857	45.697	9.835	0.289
1.2493	0.00622	1.0070	0.83017	0.01824	0.56857	45.720	9.794	0.271
1.2483	0.00625	1.0071	0.83211	0.01820	0.56857	45.740	9.757	0.254
1.2472	0.00627	1.0071	0.83410	0.01815	0.56857	45.761	9.719	0.239
1.2463	0.00630	1.0071	0.83593	0.01811	0.56857	45.781	9.684	0.226
1.2452	0.00632	1.0071	0.83799	0.01807	0.56857	45.802	9.645	0.212
1.2442	0.00635	1.0071	0.84001	0.01803	0.56857	45.823	9.607	0.199
1.2431	0.00637	1.0072	0.84211	0.01798	0.56857	45.845	9.568	0.187
1.2419	0.00640	1.0072	0.84464	0.01793	0.56857	45.871	9.520	0.176
1.2405	0.00644	1.0072	0.84730	0.01787	0.56857	45.898	9.471	0.165
1.2392	0.00647	1.0072	0.85002	0.01782	0.56857	45.925	9.420	0.154
1.2379	0.00651	1.0073	0.85271	0.01776	0.56857	45.952	9.370	0.145
1.2365	0.00654	1.0073	0.85554	0.01770	0.56857	45.980	9.318	0.136
1.2352	0.00658	1.0073	0.85832	0.01765	0.56857	46.008	9.267	0.127
1.2338	0.00662	1.0073	0.86125	0.01759	0.56857	46.037	9.214	0.119
1.2324	0.00666	1.0074	0.86423	0.01753	0.56857	46.066	9.159	0.111
1.2311	0.00669	1.0074	0.86697	0.01748	0.56857	46.092	9.110	0.104
1.2297	0.00673	1.0074	0.87003	0.01742	0.56857	46.122	9.055	0.0976
1.2283	0.00677	1.0075	0.87304	0.01736	0.56857	46.150	9.001	0.0913
1.2269	0.00682	1.0075	0.87619	0.01730	0.56857	46.180	8.945	0.0852
1.2255	0.00686	1.0075	0.87927	0.01724	0.56857	46.209	8.891	0.0797
1.2240	0.00690	1.0075	0.88249	0.01718	0.56857	46.239	8.834	0.0743
1.2226	0.00695	1.0076	0.88574	0.01712	0.56857	46.269	8.777	0.0693
1.2212	0.00699	1.0076	0.88893	0.01706	0.56857	46.298	8.722	0.0647
1.2198	0.00704	1.0076	0.89225	0.01700	0.56857	46.328	8.664	0.0603
1.2184	0.00708	1.0077	0.89550	0.01695	0.56857	46.357	8.608	0.0563
1.2170	0.00713	1.0077	0.89888	0.01689	0.56857	46.387	8.551	0.0524
1.2155	0.00718	1.0077	0.90229	0.01683	0.56857	46.417	8.493	0.0488
1.2143	0.00722	1.0077	0.90540	0.01678	0.56857	46.444	8.440	0.0457
1.2128	0.00727	1.0078	0.90886	0.01672	0.56857	46.474	8.382	0.0425
1.2115	0.00732	1.0078	0.91224	0.01666	0.56857	46.503	8.326	0.0396
1.2100	0.00737	1.0078	0.91576	0.01660	0.56857	46.533	8.268	0.0369
1.2087	0.00742	1.0079	0.91918	0.01655	0.56857	46.561	8.212	0.0343
1.2073	0.00748	1.0079	0.92274	0.01649	0.56857	46.591	8.153	0.0319

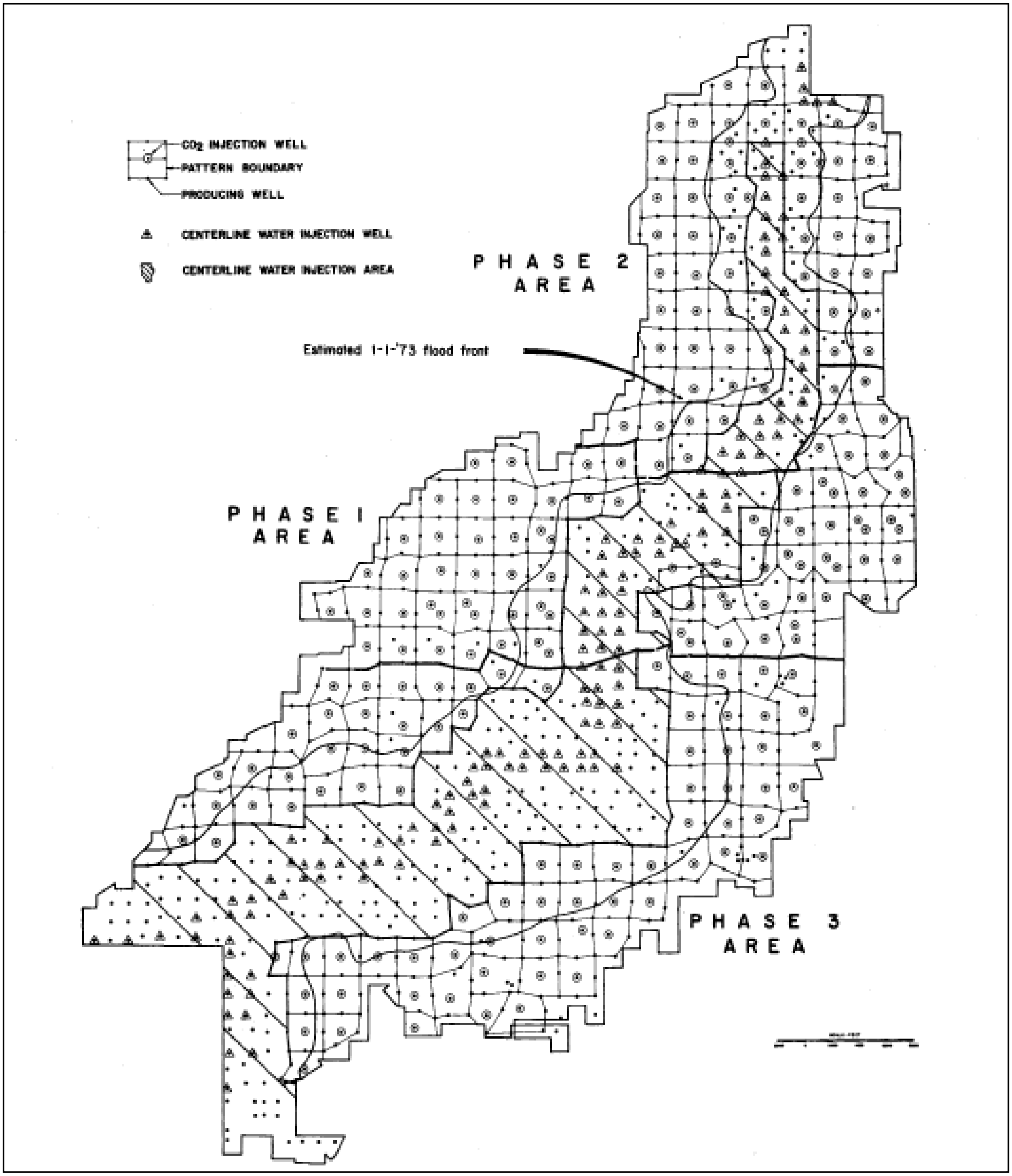
1.2059	0.00753	1.0079	0.92633	0.01643	0.56857	46.621	8.095	0.0296
1.2045	0.00758	1.0080	0.92983	0.01638	0.56857	46.649	8.039	0.0276
1.2032	0.00764	1.0080	0.93346	0.01632	0.56857	46.679	7.981	0.0256
1.2018	0.00769	1.0080	0.93699	0.01627	0.56857	46.707	7.925	0.0238
1.2004	0.00775	1.0080	0.94067	0.01621	0.56857	46.736	7.867	0.0221
1.1991	0.00781	1.0081	0.94436	0.01616	0.56857	46.765	7.810	0.0205
1.1978	0.00786	1.0081	0.94784	0.01611	0.56857	46.793	7.756	0.0191
1.1965	0.00792	1.0081	0.95157	0.01605	0.56857	46.821	7.699	0.0177
1.1952	0.00798	1.0082	0.95520	0.01600	0.56857	46.849	7.643	0.0164
1.1938	0.00804	1.0082	0.95898	0.01595	0.56857	46.878	7.586	0.0152

Gas Rel. Perm. (fraction)	Water Rel. Perm. (fraction)	Water Cut (percent)	Solution GOR (scf/STB)	Producing GOR (scf/STB)	Cum GOR (scf/STB)	GLR (scf/STB)	Mole % H2S (percent)	Mole % CO2 (percent)
0	0		500				0.00	0.00
0	0.027	0.000	500	500	500	500	0.00	0.00
0	0.0281	0.000	500	500	500	500	0.00	0.00
0	0.0291	0.000	500	500	500	500	0.00	0.00
0	0.0298	0.000	500	500	500	500	0.00	0.00
0	0.0303	0.000	500	500	500	500	0.00	0.00
0	0.0305		500		500		0.00	0.00
0	0.0308	0.000	500	500	500	500	0.00	0.00
0	0.0311	0.000	500	500	500	500	0.00	0.00
0	0.0314	0.000	500	500	500	500	0.00	0.00
0	0.0317	0.000	500	500	500	500	0.00	0.00
0	0.0319	0.000	500	500	500	500	0.00	0.00
0	0.0321	0.000	500	500	500	500	0.00	0.00
0	0.0323	0.000	500	500	500	500	0.00	0.00
0	0.0325	0.000	500	500	500	500	0.00	0.00
0	0.0326	0.000	500	500	500	500	0.00	0.00
0	0.0328	0.000	500	500	500	500	0.00	0.00
0	0.0329	0.000	500	500	500	500	0.00	0.00
0	0.0331	0.000	498	500	500	500	0.00	0.00
0	0.0332	0.000	496	500	500	500	0.00	0.00
0	0.0333	0.000	494	500	500	500	0.00	0.00
0	0.0334	0.000	492	500	500	500	0.00	0.00
0	0.0335	0.000	490	500	500	500	0.00	0.00
0	0.0336	0.000	488	500	500	500	0.00	0.00
0	0.0336	0.000	486	500	500	500	0.00	0.00
0	0.0337	0.000	484	500	500	500	0.00	0.00
0	0.0338	0.000	483	500	500	500	0.00	0.00
0	0.0339	0.000	481	500	500	500	0.00	0.00
0	0.0339	0.000	479	500	500	500	0.00	0.00
0	0.034	0.000	477	500	500	500	0.00	0.00
0	0.0341	10.760	474	500	500	446	0.00	0.00
0	0.0341	10.999	472	500	500	445	0.00	0.00
0	0.0342	11.243	469	500	500	444	0.00	0.00
0	0.0342	11.482	467	500	500	443	0.00	0.00
0	0.0343	11.715	464	500	500	441	0.00	0.00
0	0.0343	11.949	462	500	500	440	0.00	0.00
0	0.0344	12.177	459	500	500	439	0.00	0.00

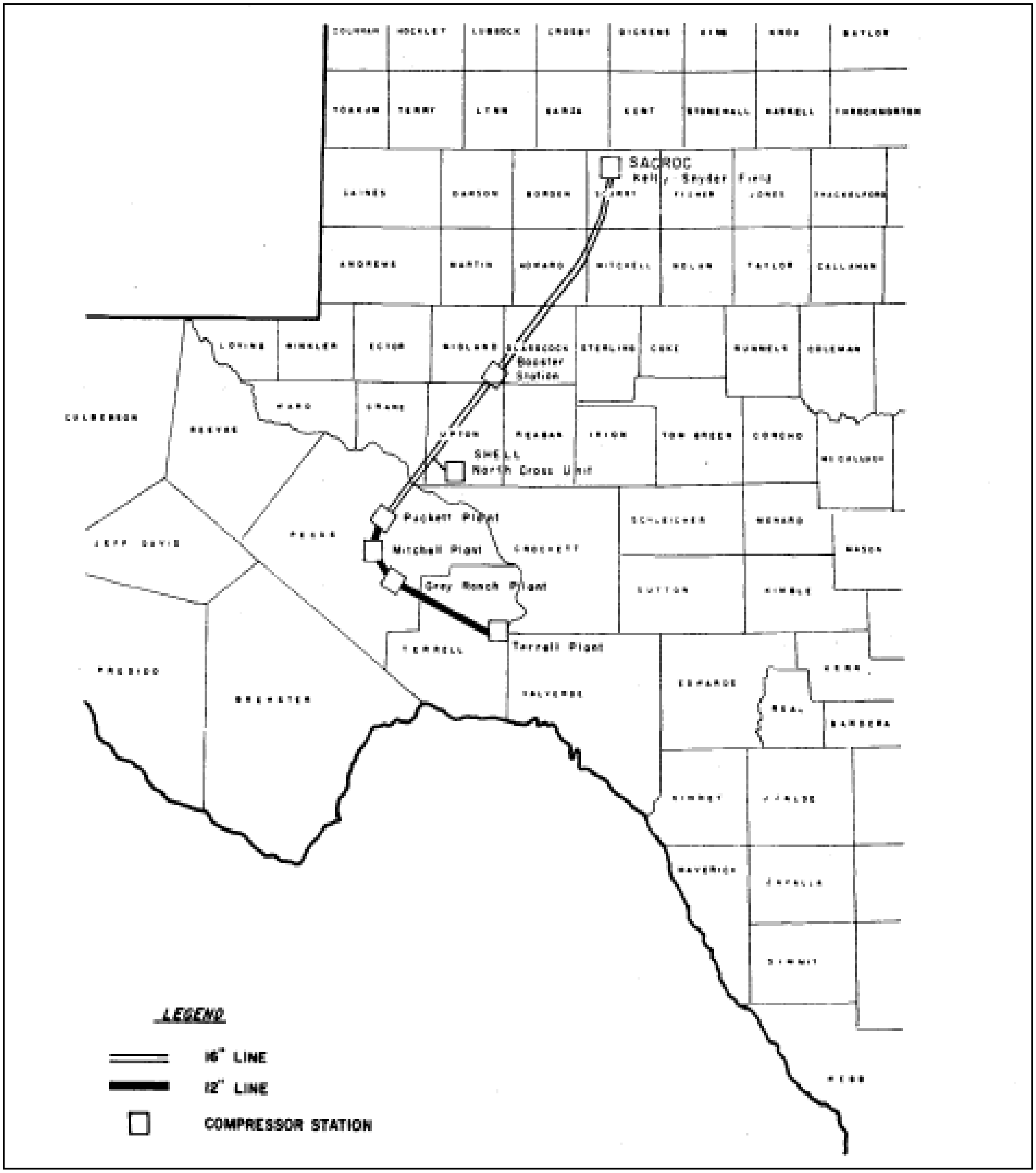
Appendix VI: Performance of Kelly-Snyder oil field



Appendix VII: MAP of field with CO_2 injection well

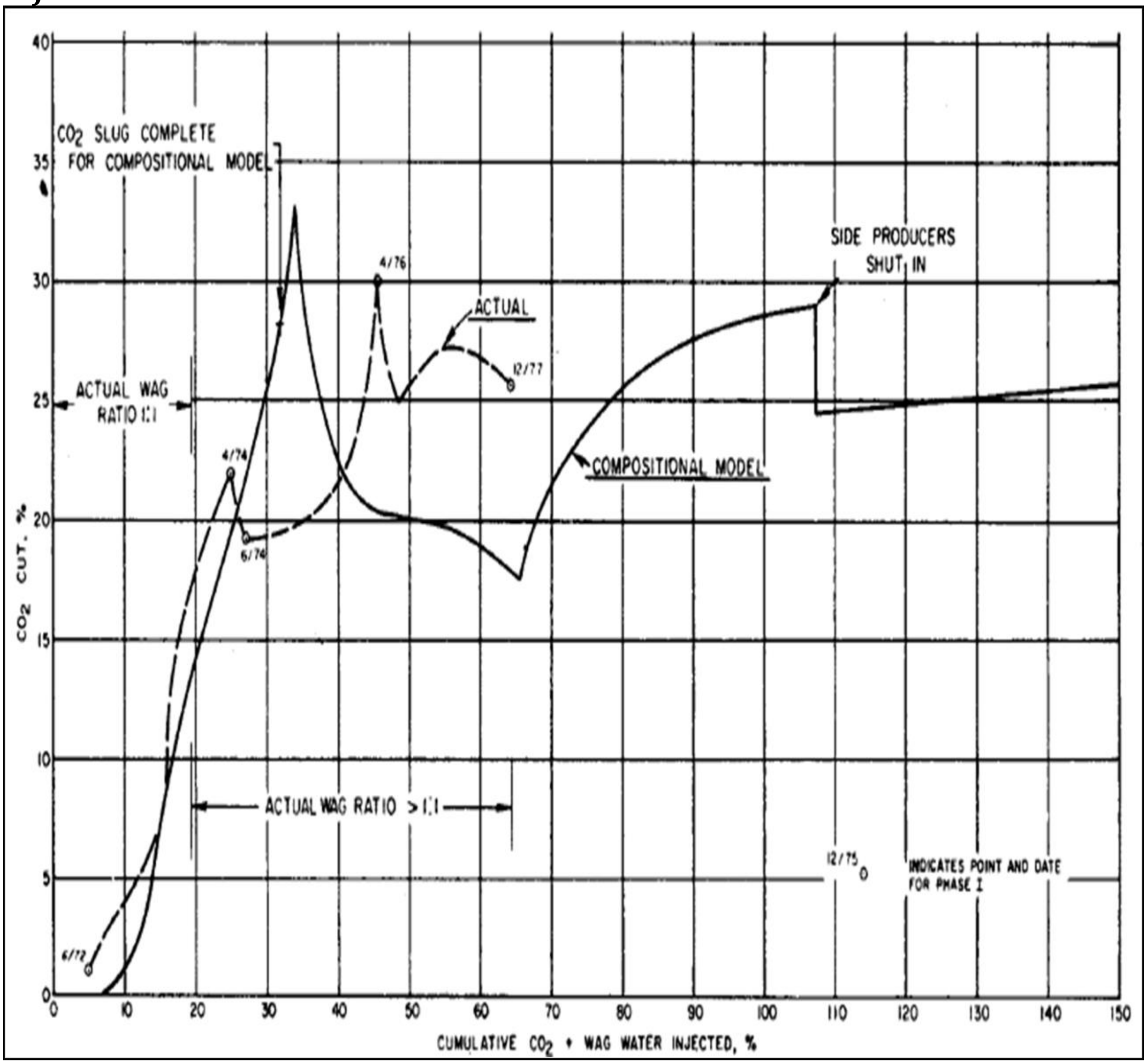


Appendix VIII: CO_2 supply system of SACROC

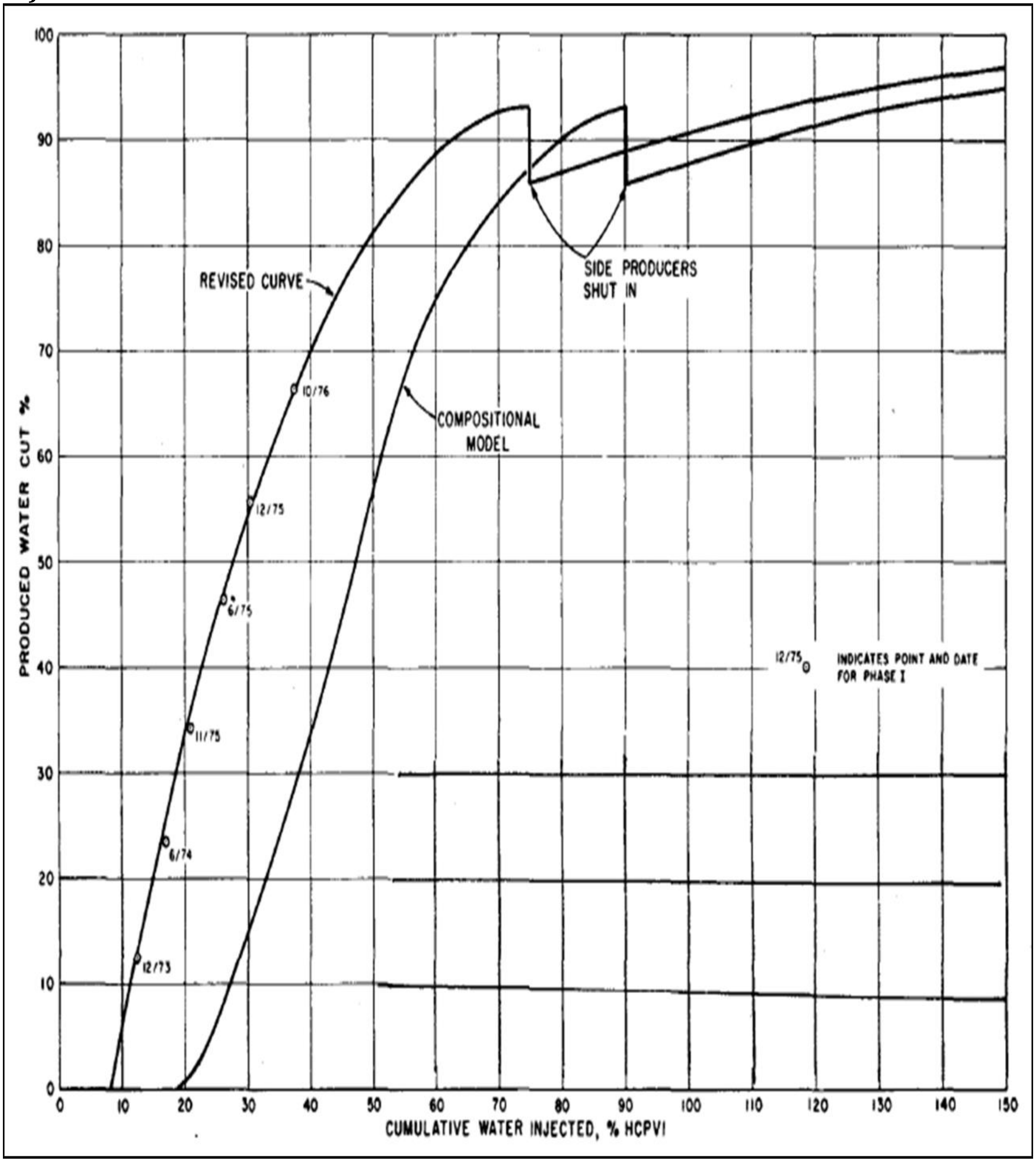


Appendix IX: Performance curves to compare compositional model and actual CO_2 cut performance

A)

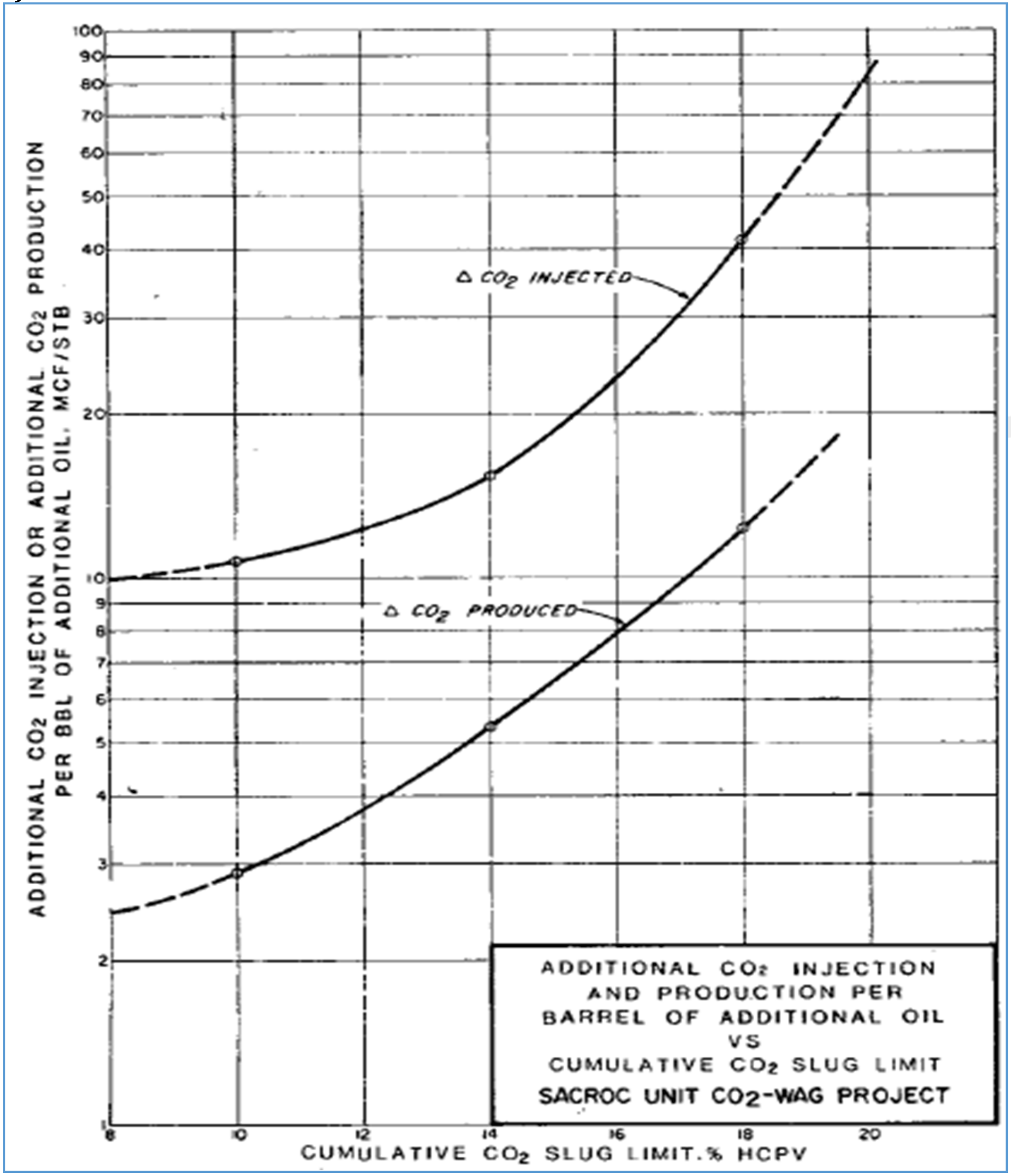


B)



PRODUCED WATER CUT %
CUMULATIVE WATER INJECTED, % HCPVI
REVISED CURVE
COMPOSITIONAL MODEL
SIDE PRODUCERS SHUT IN
12/75 INDICATES POINT AND DATE FOR PHASE I
12/73
6/74
11/75
6/75
12/75
10/76
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150

C)


ADDITIONAL CO2 INJECTION OR ADDITIONAL CO2 PRODUCTION PER BBL OF ADDITIONAL OIL, MCF/STB
100
90
80
70
60
50
40
30
20
10
9
8
7
6
5
4
3
2
1
Δ CO2 INJECTED
Δ CO2 PRODUCED
8
10
12
14
16
18
20
CUMULATIVE CO2 SLUG LIMIT, % HCPV
ADDITIONAL CO2 INJECTION AND PRODUCTION PER BARREL OF ADDITIONAL OIL VS CUMULATIVE CO2 SLUG LIMIT
SACROC UNIT CO2-WAG PROJECT