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Life beyond 80 - A look at Conventional WAG Recovery beyond 80% HCPV Injection in CO_2 Tertiary Floods

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Abstract

During the past 38 years, CO_2 flood technology for Enhanced Oil Recovery projects evolved from a partially understood process filled with uncertainties to a process based on proven technology and experience. Many questions involved with CO_2 flooding have been thoroughly analyzed and answered. This knowledge is currently being used by a limited number of companies that actually know how to design, implement, and manage a CO_2 flood for long term profit. Unfortunately, this knowledge has not been disseminated to operating companies interested in EOR flooding or to CO_2 Sequestration Communities interested in storing CO_2 in EOR projects.

The primary objective of this report is to target "Conventional WAG Techniques" which have been used in over 90% of all the Enhanced Oil Recovery projects implemented in the Permian Basin in Texas, Colorado, Oklahoma, and Wyoming. Over the years, oil companies have reported a wide range of values of Tertiary Oil Recovery, CO_2 Utilization, and CO_2 Retention, resulting in a wide range of variation and uncertainty. Many of the numbers reported to date are tied to a specific HCPV CO_2 Injected based on some Economic Cut-off. This typically has been in the range of 30% to 80% HCPV Injected. The question becomes "What is life after 80% HCPV?" And "What effect does life after 80% HCPV have on Tertiary Oil Recovery, CO_2 Utilization and CO_2 Retention in different producing formations?" Results of this study show Tertiary Oil Recovery can be as high as 26% OOIP when slug sizes exceed 190% HCPV injected.

Carbon Sequestration Options: Five Recovery Methods for Enhanced Oil Recovery (EOR)

Most Enhanced Oil Recovery Projects use one of the following five operating methods: Conventional WAG Recovery, Gravity-stabilized Recovery, Double Displacement, Gas-cycling or Huff-and-Puff. The primary difference between methods depends on the reservoir geology and well pattern configuration. In Conventional CO_2 floods, typical of West Texas, the formations are basically flat (Ramp Sequence), low perm, the fields are developed on pattern spacing (e.g. 5-spot patterns, 9-spot patterns, or Chickenwire patterns), and Conventional WAG Operating schemes are used to control mobility and CO_2 flood response. In conventional WAG operations, the objective is to minimize the amount of CO_2 purchased (CO_2 stored in Sequestration projects), which is typically in the range of range of 30%-40% of the total HCPV CO_2 injected. In un-conventional Gravity-Stabilized and Double Displacement case histories, Flue Gas, CO_2, Lean Gas or N_2 is usually injected in the top of the structure and oil is produced from the bottom. More CO_2 can be sequestered than conventional WAG operations. As much as 80% of the total pore volume can be displaced with CO_2. However, the reservoir must meet certain fluid-dynamic criteria and have structure to make the gravity-stabilized process work. In Gas-cycling projects, typical of projects operated by Denbury in Mississippi, CO_2 is cycled through the formation. As much as 6 pore-volumes of CO_2 are injected to recover 18% OOIP. In Huff-and-Puff operations, the CO_2 is injected into and produced from the same well. The objective is to mobilize tertiary oil in the near vicinity of the well-bore, and then produce the CO_2 and tertiary oil back. Then repeat the process (typically with 3 cycles). The process technically works. The economic success or failure depends on many factors. The amount of CO_2 sequestered is minimal when compared to the other recovery methods.

Conventional WAG Recovery

Conventional WAG Operating Methods in the Permian Basin fall into one of four categories:

1. Continuous CO_2 Injection
2. Constant WAG Injection
3. Tapered WAG Injection
4. Simultaneous CO_2 Injection (Limited use)

What is WAG Management?

All Conventional WAG Injection Projects have one thing in common. CO_2 is injected into the reservoir and the produced recycle CO_2 must be re-injected back into the reservoir to maximize oil recovery. This was first demonstrated by Caudle and Dyes in 1958 when water was added to CO_2 to decrease solvent mobility [Turek, 1]. As CO_2 technology was transferred from the lab to the field, most all of the Major Oil Companies in the 1970's and early 1980's adopted the use of Constant Water-Alternating-Gas (WAG) Injection based on the theory that alternate gas water injection is necessary to maintain mobility control and maximize oil recovery. During the late 1980's, Tapered WAG Operations were adopted to improve the overall recovery process [Merchant, 2,3,4,5, and 6]. WAG Injection can be best demonstrated as shown in Figure 1a and 1b. CO_2 and Water are injected into the reservoir in alternating CO_2 and water slug sizes. For Constant WAG operating schemes, the half cycle slug size is typically fixed for example at 1.0% HCPV CO_2 for the Gas Cycle and 1.0% H_2O for water. For Tapered Wag projects, WAG Ratios change with time. Typically for most CO_2 operations today, "Wetting the WAG" or increasing water half cycle volume with time improves conformance by slowing the gas in the fast zones. The water half cycle can be increased or decreased to help operational switch times in the field to improve overall conformance problems or adjusted to "Level Load" gas production to a Plant inlet rate improving overall project economics while maximizing oil recovery.

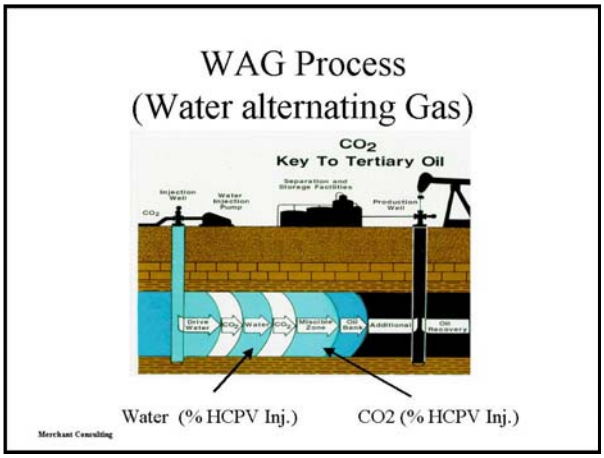


Figure 1a. Conventional WAG Process

DIFFERENT OPERATORS

DIFFERENT PHILOSOPHIES
(Reservoir Driven)

- Continuous CO_2 - Continuously Inject CO_2 (No Water)
- Constant WAG - Example: 1:1 WAG with (1.0% CO_2, 1.0% H_2O)
  Note: No change in WAG Ratio with time
- Simultaneous WAG: Hourly WAG Changes
- Tapered WAG - Combination of both Continuous and WAG

Example:	Continuous Injection	for 20% HCPV
	WAG (1.0% CO_2, 0.10% H_2O)	for 5% HCPV
	WAG (1.0% CO_2, 0.50% H_2O)	for 10% HCPV
	WAG (1.0% CO_2, 1.00% H_2O)	for 20% HCPV
	WAG (1.0% CO_2, 1.50% H_2O)	for 30% HCPV
	Chase Water Injection	

Note: Total CO_2 Slug Size = 85% HCPV Injection of CO_2

Figure 1b. Conventional WAG Process

Reservoir Modelling

Through the 1980's and 1990's, Amoco, Shell, Arco, Mobil, and Texaco committed significant manpower to evaluate the feasibility of full field scale CO_2 flooding in the Permian Basin. Before the initiation of field scale floods, many pilots were drilled and much reservoir simulation was conducted to understand the CO_2 flooding process. Today, there are over 82 active CO_2 projects in the United States producing over 237,000 BOPD and CO_2 flooding is expanding to many parts of the world. Reservoir simulation has been an integral part of reservoir management in understanding the CO_2 flood tertiary recovery process. Reservoir Modelling was used in the development of Tapered WAG [2,3,4,5, and 6]. Simulation today is used in the initial design of slug sizes and gas-water ratios (GWR), and allows Reservoir Engineers to explore different operating scenarios that best match field performance.

The development of Reservoir Simulators over the years has permitted a greater reliability in simulating the miscible process over a wide range of injection gas-water ratios. Confidently estimating the response of the reservoir to CO_2 injection generally involves history matching Primary and Secondary performance. The model developed for this study has properties that are typical of West Texas San Andres Dolomite reservoirs. These models incorporate the latest state-of-the-art understanding of the physics and mathematics pertaining to reservoir characteristics, recovery mechanisms, and operating conditions. In 1986, the model used to develop tapered WAG was simulated with Amoco's GCOMP simulator in Blackoil mode with a miscible option (3 hydrocarbon component model). This model implies the solvent mixes with the reservoir oil in all proportions with no phase separation. Today, Compositional Simulation is being used to simulate the miscible process.

Model Development

For this analysis, it was important to determine if the predictions generated by the simulator reasonably agreed with actual field performance. The model used in this study incorporates historical production and injection waterflood performance from the Slaughter Estate Unit in Slaughter field and scaled to a single five-spot pattern [2,3,4,5, and 6]. In addition, lessons learned from full-field CO_2 flooding experience provided additional insight of both reservoir heterogeneity and understanding of the complex CO_2 flood process. The Model represents an inverted 5-spot (10X10X6 Grid) Well Configuration with Injector in the middle and one-quarter Producers located on the corners. The model contains six layers with phi-h and k-h varying areally. The model contains both a Primary Recovery Period as well as a Secondary Recovery Period of water injection. Reservoir Parameters are shown on the next page in Table 1.

Table 1 – Model Grid Properties (General)

Average Model Properties

Model Type:	Average Pattern (5-spot)
Pattern Segment Model Size - acres	25
Depth, Feet	5000
Reservoir Temperature, deg F	105
Net Pay, Feet	104
Average Porosity, percent	11.4
Average Permeability, md	6.4
Oil FVF @ Original Bubble Point RB/STB	1.228
Oil Reservoir Pressure @ 1300 feet subsea, psi	1710
Bubble Point Pressure @ 1300 feet subsea, psi	1710
CO_2 Miscibility Pressure, psi	1200
Number of Model Layers	6

Average Model Properties

Model Layer	Net-Thickness ft	Porosity-Thickness ft	Permeability-Thickness md-ft	k/phi k-h / phi-h
1	17	1.5	21.8	15
2	24	3.0	129.6	44
3	13	1.7	127.3	76
4	14	2.2	160.3	75
5	10	1.1	166.3	154
6	27	2.6	56.9	22
Total	104	11.9	662.2	56

Model – Primary and Secondary Recovery

Primary and Secondary Production and Injection History for the 25-acre model are shown on Figures 2a, 2b, 3a, and 3b. For the 25 acre model, Primary Oil Rate peaked around 125 BOPD and Secondary Oil Rate peaked around 215 BOPD.

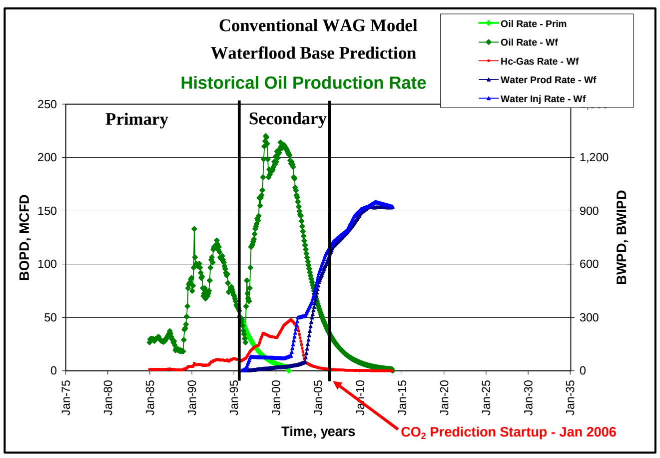


Figure 2a. – Historical Production Performance

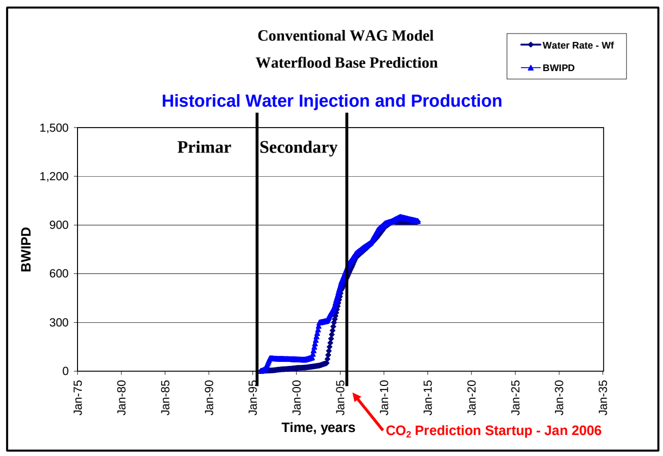


Figure 2b. – Historical Injection Performance

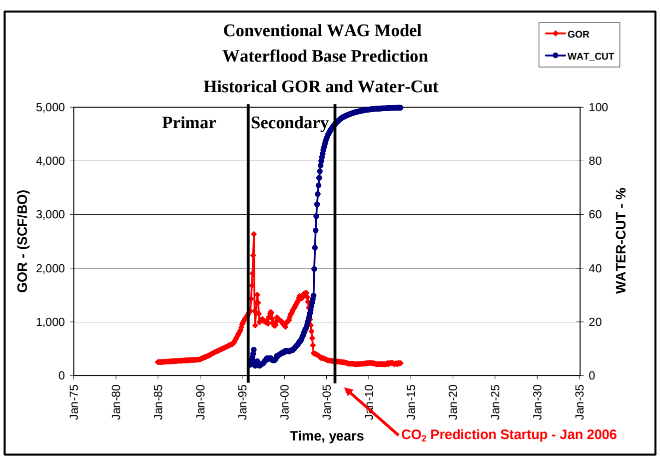


Figure 3a. – Historical GOR, Water-Cut

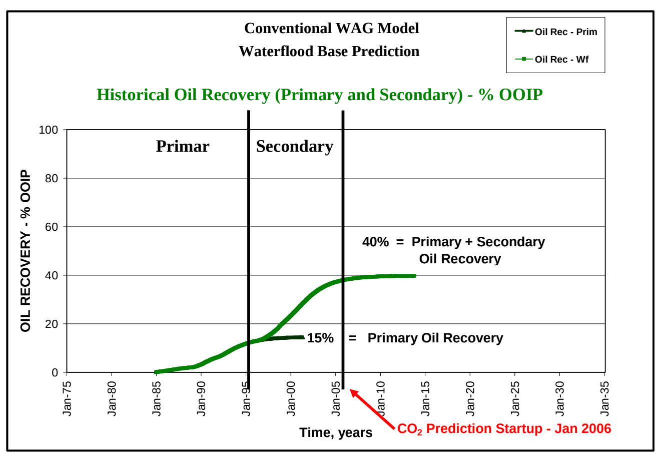


Figure 3b. – Historical Oil Recovery Performance

When conducting Tertiary CO_2 predictions, Historical Primary plus Secondary Waterflood Performance is a key parameter to achieving high Tertiary Oil Recovery. The Primary and Secondary waterflood oil recovery performance shown above is considered "Good" waterflood response when Primary plus Secondary Recovery exceed 40% OOIP. When waterflood performance is less than 40%, Tertiary Performance Predictions should be scaled-down to match historical performance.

Optimization Case Comparisons - Case Studies (20% HCPV to 80% HCPV Injected)

Future Predictions under any type of Recovery Mechanism are a very important aspect of any type of Economic Analysis. For Optimization, the factors which influence CO_2 Flood Economics are: (1) Oil and Hc-gas Price, (2) CO_2 Plant and Pipeline Capital Investment Costs, (3) CO_2 Purchase Costs (including Pipeline Tariffs), (4) CO_2 Plant Processing Costs, (5) Field Operating Costs (Workover and Lift), and (6) Overhead.

Tertiary Oil Recovery (No Economics)

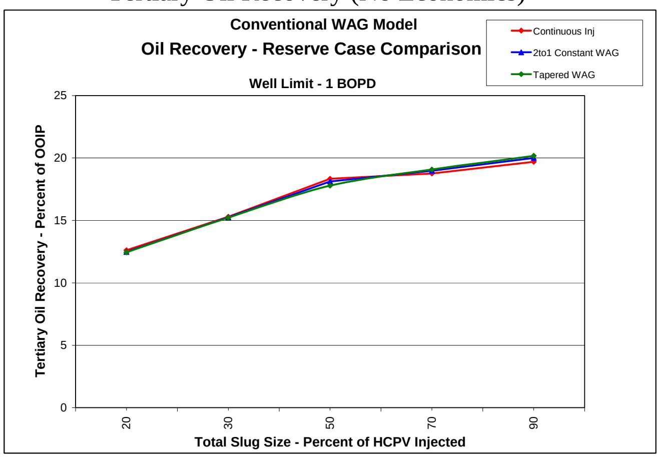


Figure 4a. – Oil Recovery (without Economics)

Tertiary Oil Recovery (With Economics)

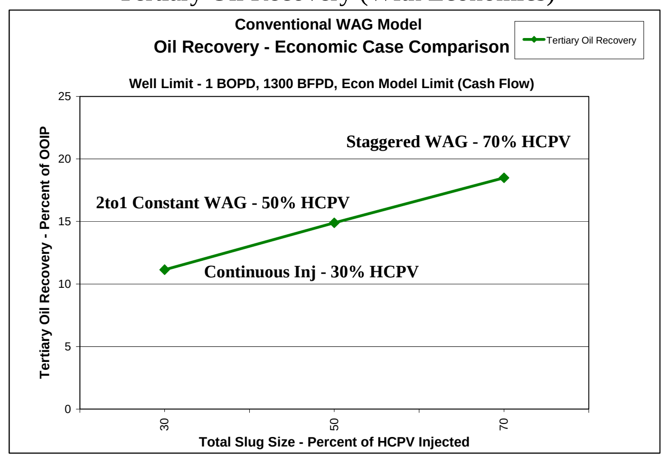


Figure 4b. – Oil Recovery (with Economics)

Tertiary Oil Recovery under CO_2 Injection is a function of the total amount of CO_2 Injected. As shown in Figure 4a, comparing total CO_2 HCPV injection between cases assuming a 1.0 BOPD cutoff (No Economics), Reservoir Recovery for the three operating methods are statistically the same. When economics are applied to each of the cases, Figure 4b, the amount of Tertiary Oil Recovered and Present Value Economics are different between cases. Based on Economics, a 30% HCPV CO_2 Slug is Economically Optimum for Continuous CO_2 Injection, a 50% HCPV CO_2 Slug is Economically Optimum for Constant WAG Injection, and a 70% HCPV CO_2 Slug is Economically Optimum for Tapered WAG Injection.

Economic Comparison - Tertiary Oil Rate and Oil Recovery

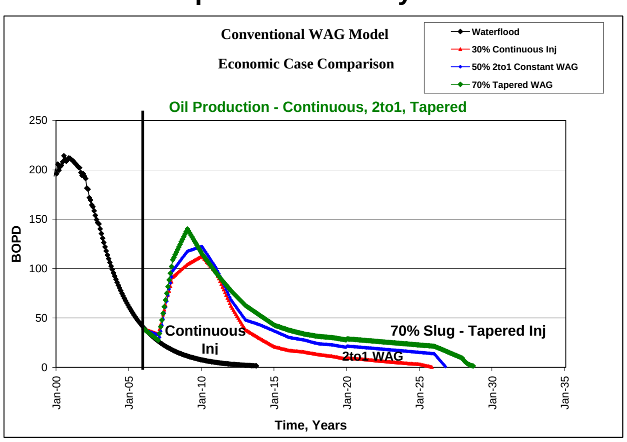


Figure 5a. – Tertiary Oil Rate

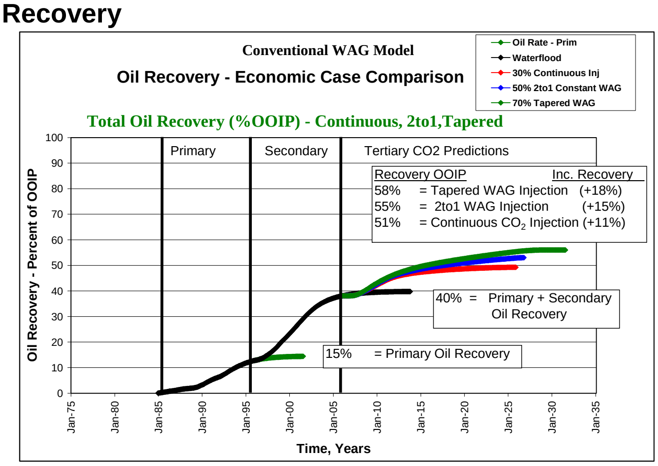


Figure 5b. – Tertiary Oil Recovery

Oil Production Rate and Tertiary Oil Recovery comparing the three Economic cases are shown above on Figures 5a and 5b. The total amount of CO_2 injected determines the amount of Tertiary Oil Recovered. The greater the amount of CO_2 injected, the greater the Tertiary Oil Recovery. The objective in a CO_2 flood is to accelerate the CO_2 Injection as quickly as possible, without fracturing the reservoir. Continuous Injection accomplishes this goal. Constant WAG Injection has the ability to control reservoir sweep, extending CO_2 flood life. Tapered WAG Injection combines the best of both. In addition to accelerating the front end Economics, it also recovers the most tertiary reserves.

Economic Comparison – CO_2 Injection and Production

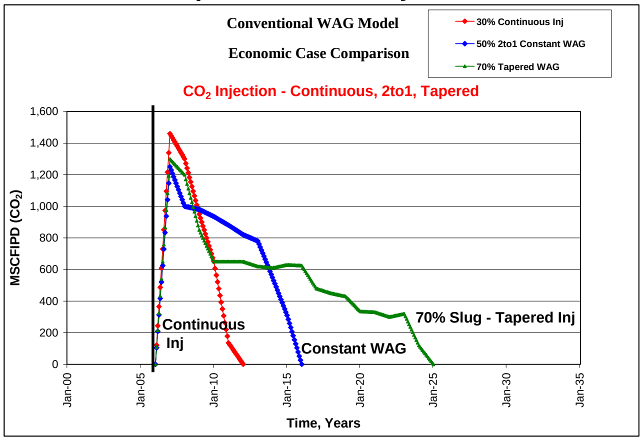


Figure 6a. – Tertiary CO_2 Injection Rate

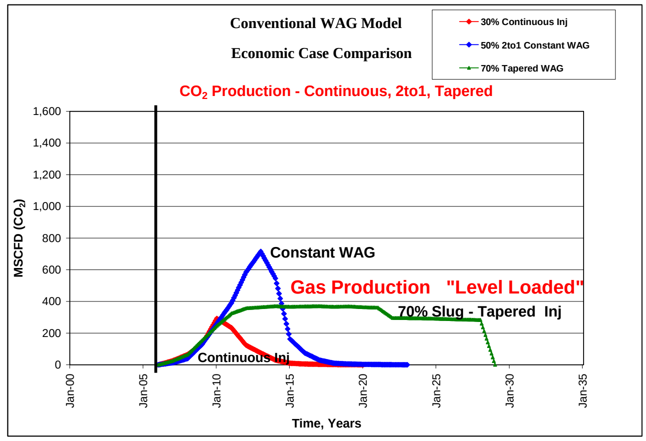


Figure 6b. – CO_2 Production Rate

CO_2 Production and its associated Plant Investment is a major component in Economic analysis. A taperd WAG operating scenario extends tertiary oil recovery beyond Continuous and Constant WAG operations by controlling CO_2 production by "Level-loading Inlet Plant Rate CO_2 Production" to a plant inlet rate to control costs.

Economic Comparison – CO_2 Purchase Rate and CO_2 Storage (CO_2 Sequestration)

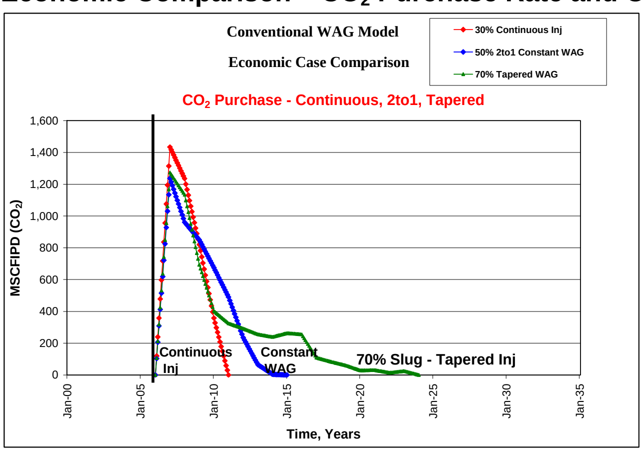


Figure 7a. – Tertiary CO_2 Purchase Rate and

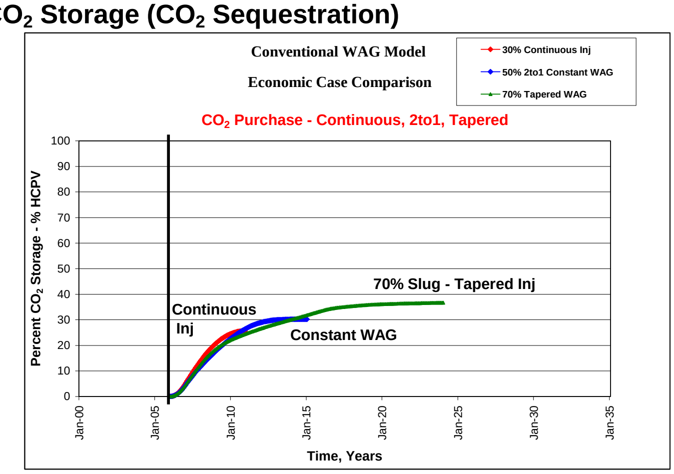
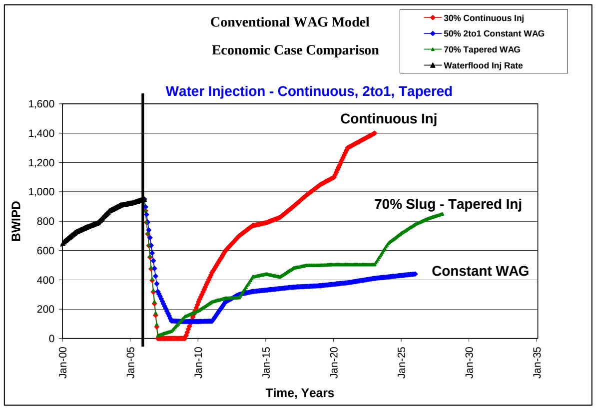


Figure 7b. CO_2 Storage Rate

The Total CO_2 Slug Size consists of two parts. The CO_2 Purchase portion always occurs at the start of the project. The Recycle Portion, which is the CO_2 recovered through production, is processed through a plant and injected back into the reservoir. The volume purchased and the purchase times for injection are dependent on the total CO_2 slug injected. In Tapered WAG designs, CO_2 is purchased throughout the life of the CO_2 flood. As shown above, the amount of CO_2 purchased declines as the tertiary flood matures.

CO_2 Sequestration

The amount of CO_2 Purchased in EOR operations is also the amount of CO_2 Sequestered in CO_2 Sequestration projects. As shown above in Figure 7b, this amount is typically in the range of 30% to 40% of the total HCPV injected. Separate from CO_2 Retention, which is the amount of CO_2 retained as a percent of total amount of CO_2 injected, the amount of CO_2 stored in the reservoir or sequestered is always 100% of the CO_2 purchased volume.



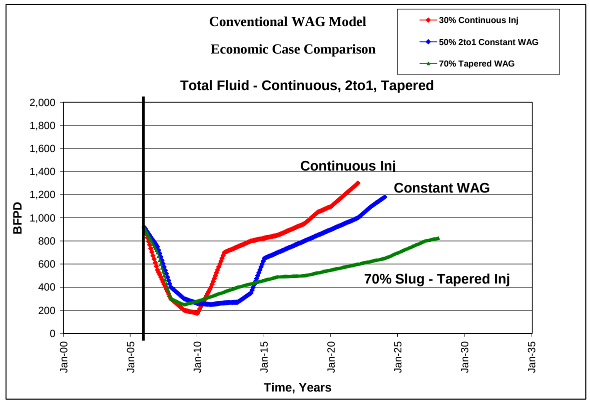
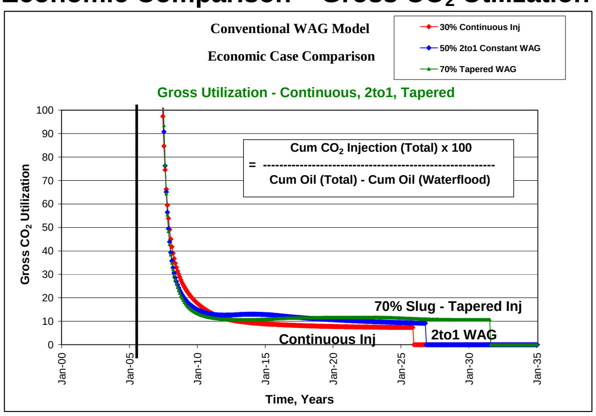


Figure 8a. – Tertiary Water Injection Rate **Figure 8b. – Total Fluid Production Rate**

The key to Optimization is the ability to control CO_2 processing costs. This is accomplished by injecting water as a mobility control agent. For this study, increasing half cycle water volumes occurred every 10% HCPV Inj CO_2. This resulted in a nearly flat CO_2 production response to "Level Load" CO_2 Gas Production Rate to a "Plant Inlet Rate".

Economic Comparison – Gross CO_2 Utilization and Net CO_2 Utilization)



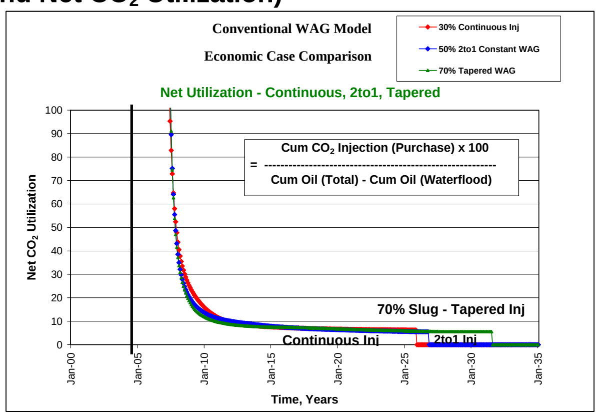


Figure 9a. – CO_2 Gross Utilization **Figure 9b. – CO_2 Net Utilization**

CO_2 Utilization is an efficiency measure of how much CO_2 is used to recovery a barrel of Tertiary Oil. Gross Utilization is defined as the Cumulative Total amount of CO_2 Injected per total amount of Tertiary Oil Produced, typically 10 to 20 MSCF/BO. Net CO_2 Utilization is defined as the Cumulative Purchased amount of CO_2 per total amount of Tertiary Oil Produced, typcically in the range of 5-10 MSCF/BO.

Economic Comparison – CO_2 Retention

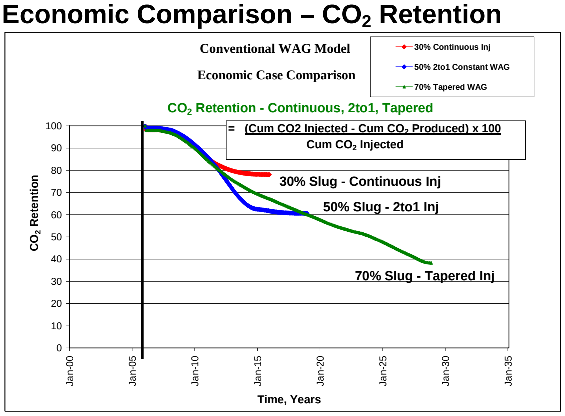


Figure 10a. – CO_2 Retention

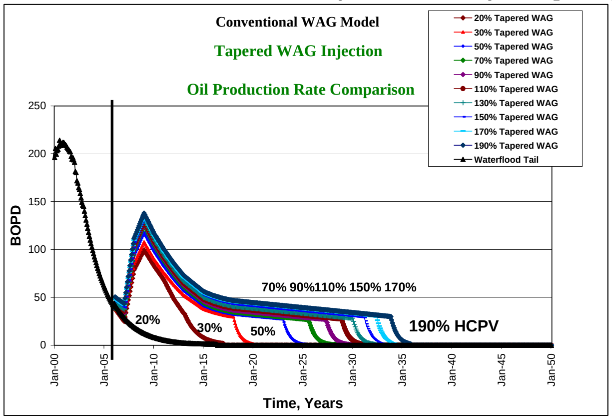
CO_2 Retention is an Engineering term used to relate the total amount of CO_2 retained in the reservoir to the total amount of CO_2 injected. It repreents the percent of Cumulative CO_2 Injected minus Cumulative CO_2 Produced divided by the amount of Cumulative CO_2 Injected. As the CO_2 flood matures, the retention will decrease from 100% to some minimum value.

Life beyond 80% HCPV- Tapered WAG Injection (20% HCPV to 190% HCPV Injected)

The question becomes “What is life after 80% HCPV?” And “What effect does life after 80% HCPV have on CO_2 Utilization and CO_2 Retention in different producing formations?” The answer to those questions is shown below.

Life beyond 80% HCPV - Tertiary Oil Rate and Oil Recovery

Oil Production Rate and Tertiary Oil Recovery comparing the extended CO_2 Slug size fom 20% HCPV to 190% HCPV



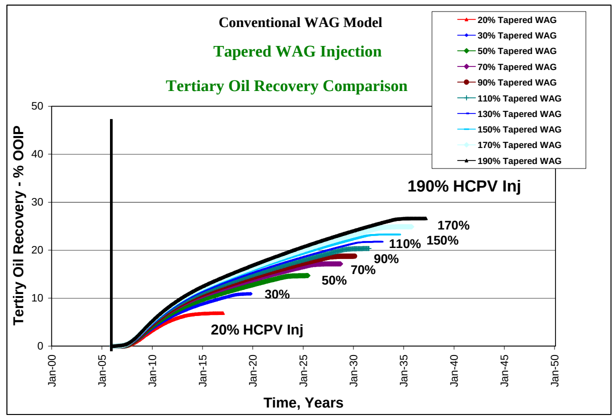
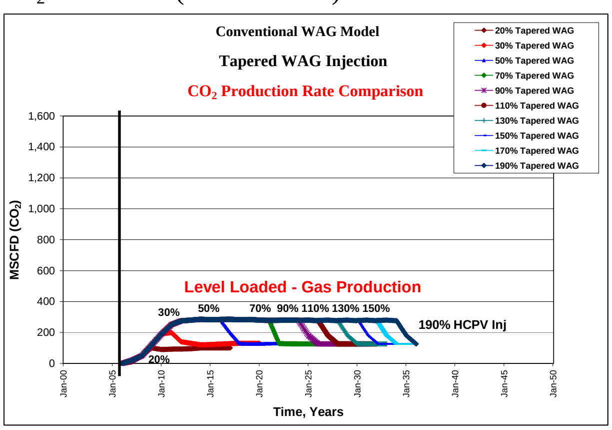


Figure 11a – Tertiary Oil Rate (Tapered WAG) **Figure 11b. – Tertiary Oil Recovery (Tapered WAG)**

CO_2 Production (Level Loaded) and Total Fluid Rate comparing CO_2 Slug size fom 20% HCPV to 190% HCPV



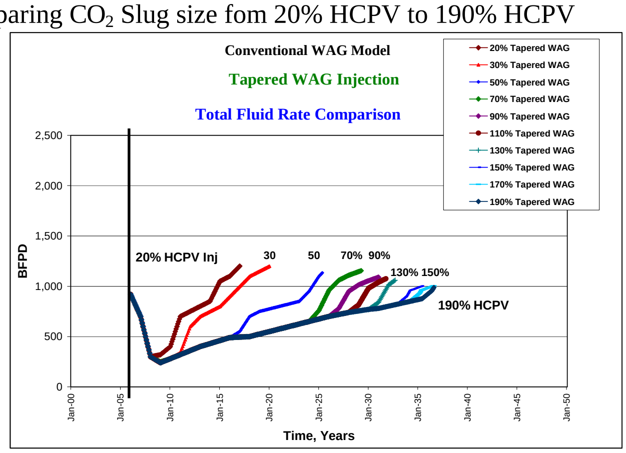


Figure 12a – Tertiary CO_2 Rate (Tapered WAG) **Figure 12b – Total Fluid Rate (Tapered WAG)**

As shown above, extending Total CO2 slug size beyond 80% HCPV extends Teritary Oil Recovery. A 190% HCPV slug size improves Tertiary Oil Recovery to 26% OOIP.

Factors that control Tertiary Oil Recovery

The ability to achieve High Tertiary Recovery in New CO_2 floods depends on the following factors:

1. Large Original Oil-in-Place
2. Rock Type: Dolomite and Sandstone better than Limestone, Un-fractured Formations better than Fractured Formations
3. Good Pattern Development – Fields with many patterns achieve the highest tertiary recovery
4. Historical Primary and Secondary Waterflood Performance (Prim + Secondary Rec should be above 40% OOIP)
5. Primary + Secondary + Tertiary Recovery less than 70% OOIP (CO_2 will never remove all the oil)
6. CO_2 miscible with the oil (100% efficiency is best but can be operated below MMP)
7. Good Reservoir Conformance between injectors and producers
8. Good Porosity, Good Permeability, and Good k/phi distribution
9. Good Residual Oil Saturation Target (Approx. Range: Dolomites – 30%, Cherts – 25%, Sandstones – 20%)
10. Good Economics: High Oil Price, Low CO_2 Purchase Price, Low Recycle Plant and Field Capital Investments
11. CO_2 Source that is reliable and of high quality (Pipeline in close proximity)
12. Conventional WAG should be able to Sequester or STORE 30% to 40% HCPV (CO_2 Purchase Volume)

Life beyond 80% HCPV- (Tertiary Oil Recovery, CO_2 Gross and Net Utilization)

Since 1972, over 100 Commercial CO_2 floods have been operated in the United States, with 72 of these projects still active today. During this time, Engineers have reported a wide range of Tertiary Oil Recovery, Gross Utilization and Net Utilization values at varying stages of maturity. The question becomes "What would Operators report on these CO_2 floods today?" And "What would Oil Recovery, Gross Utilization and Net Utilization look like under Extended CO_2 Slug volumes?" The answer to those questions depends on Reservoir Type. Data from these CO_2 projects from various SPE and DOE reports are listed below by formation type:

Table 2. - San Andres and Grayburg Formation – Dolomite

				Current Economic			Life beyond 80% HCPV Inj			
State	Formation	Field	Lease	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Tertiary Recovery (%OOIP)	Gross CO2 Utilization (MSCF/STB)	Net CO2 Utilization (MSCF/STB)	Bibliography References
Texas	San Andres	Wasson	Denver Unit	15 to 20	10 to 15	5 to 10	20 to 25	5 to 10	1 to 5	7,8,9,10
Texas	San Andres	Wasson	Denver Unit-ROZ	10 to 15	15 to 20	5 to 10	15 to 20	10 to 15	5 to 10	11,18
Texas	San Andres	Wasson	Wasson ODC Unit	15 to 20	10 to 15	5 to 10	20 to 25	5 to 10	1 to 5	12
Texas	San Andres	Wasson	Cornell Unit	15 to 20	10 to 15	5 to 10	20 to 25	5 to 10	1 to 5	13
Texas	San Andres	Wasson	Bennett Ranch Unit	15 to 20	10 to 15	5 to 10	20 to 25	5 to 10	1 to 5	14,15
Texas	San Andres	Wasson	Willard Unit	15 to 20	10 to 15	5 to 10	20 to 25	5 to 10	1 to 5	16
Texas	San Andres	Seminole	Seminole Unit-Main Pay	20 to 25	10 to 15	5 to 10	25 to 30	5 to 10	1 to 5	17
Texas	San Andres	Seminole	Seminole Unit-ROZ	10 to 15	15 to 20	5 to 10	15 to 20	10 to 15	5 to 10	11,18
Texas	San Andres	Slaughter	Slaughter Estate Unit	15 to 20	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	19 thru 24
Texas	San Andres	Slaughter	Frazier Unit	15 to 20	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	
Texas	San Andres	Slaughter	Central Mallet Unit	15 to 20	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	25
Texas	San Andres	Slaughter	Slaughter Sundown	15 to 20	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	26, 27,28
Texas	San Andres	Slaughter	Mobil Mallet Unit	15 to 20	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	29
Texas	San Andres	Slaughter	H T Boyd Unit	15 to 20	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	
Texas	San Andres	Slaughter	Igoe Smith	15 to 20	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	
Texas	San Andres	Slaughter	Alex Slaughter Estate	15 to 20	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	
Texas	San Andres	Levelland	Levelland	5 to 10	15 to 20	5 to 10	10 to 15	15 to 20	5 to 10	30,31,32
Texas	San Andres	Means (San Andres)	Means (San Andres)	10 to 15	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	33,34
Texas	San Andres	Goldsmith	Goldsmith	10 to 15	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	35,36
Texas	San Andres	Hanford	Hanford	10 to 15	15 to 20	5 to 10	20 to 25	10 to 15	5 to 10	37
New Mexico	Grayburg San Andres	Vacuum	East Vacuum	10 to 15	15 to 20	5 to 10	15 to 20	10 to 15	5 to 10	38,39
New Mexico	Grayburg San Andres	Vacuum	Central Vacuum	10 to 15	15 to 20	5 to 10	15 to 20	10 to 15	5 to 10	40
New Mexico	Grayburg San Andres	Maljamar	Maljamar Unit	10 to 15	15 to 20	5 to 10	15 to 20	10 to 15	5 to 10	41,42
New Mexico	Grayburg San Andres	North Hobbs	North Hobbs	10 to 15	15 to 20	5 to 10	15 to 20	10 to 15	5 to 10	
Texas	San Andres	East Penwell (SA) Unit	East Penwell (SA) Unit	5 to 10	15 to 20	5 to 10	10 to 15	15 to 20	5 to 10	
Texas	Grayburg	Mabee	Mabee	10 to 15	15 to 20	5 to 10	15 to 20	10 to 15	5 to 10	43
Texas	San Andres	GMK South	GMK South	5 to 10	15 to 20	5 to 10	10 to 15	15 to 20	5 to 10	44
Texas	San Andres	Adair San Andres Unit	Adair San Andres Unit	5 to 10	15 to 20	5 to 10	10 to 15	15 to 20	5 to 10	
Texas	San Andres	Cedar Lake	Cedar Lake	5 to 10	15 to 20	5 to 10	5 to 10	15 to 20	5 to 10	
Texas	San Andres	Welch	West Welch	5 to 10	15 to 20	5 to 10	10 to 15	10 to 15	5 to 10	45
Texas	San Andres	Welch	South Welch	5 to 10	15 to 20	5 to 10	10 to 15	10 to 15	5 to 10	46
Texas	Grayburg San Andres	Cowden	North Cowden Demo.	5 to 10	15 to 20	5 to 10	5 to 10	15 to 20	5 to 10	
Texas	San Andres	Cowden	South Cowden	5 to 10	15 to 20	5 to 10	5 to 10	15 to 20	5 to 10	47, 48

Table 3. - Clearfork Formation – Limestone (Tight - Low Permeability)

				Current Economic			Life beyond 80% HCPV Inj			
State	Formation	Field	Lease	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Bibliography References
Texas	Clearfork	Anton Irish	Anton Irish	5 to 10	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	49
Texas	Clearfork	Wasson (South)	Wasson (South)	1 to 5	10 to 15	5 to 10	1 to 5	10 to 15	5 to 10	50

Table 4. - Devonian Formation – Tripolitic Chert

				Current Economic			Life beyond 80% HCPV Inj			
State	Formation	Field	Lease	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Bibliography References
Texas	Devonian	Dollarhide	Dollarhide Devonian Unit	10 to 15	5 to 10	1 to 5	15 to 20	5 to 10	1 to 5	51 thru 54
New Mexico	Devonian	Dollarhide	West Dollarhide Unit	10 to 15	5 to 10	1 to 5	15 to 20	5 to 10	1 to 5	
Texas	Devonian	Dollarhide	North Dollarhide Unit	5 to 10	5 to 10	1 to 5	10 to 15	5 to 10	1 to 5	55
Texas	Devonian	North Cross	N. Cross-Devonian Unit	35 to 40	5 to 10	1 to 5	40 to 45	5 to 10	1 to 5	56-57

Table 5. - Canyon Reef Formation – Karsted Limestone (High Permeability)

				Current Economic			Life beyond 80% HCPV Inj			
State	Formation	Field	Lease	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Bibliography References
Texas	Canyon Reef	Kelly Snyder (Sacroc)	Sacroc Unit	10 to 15	10 to 15	5 to 10	15 to 20	10 to 15	5 to 10	58 thru 65
Texas	Canyon Reef	Salt Creek	Salt Creek	10 to 15	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	66,67
Texas	Canyon Reef	Sharon Ridge	Sharon Ridge	5 to 10	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	68
Texas	Canyon Reef	Cogdell	Cogdell	5 to 10	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	69

Table 6. - Strawn, Morrow, Delaware, Springer, Marmaton, and Yates (Fluivial Deltaic, Point Bar, Turbidite)

				Current Economic			Life beyond 80% HCPV Inj			
State	Formation	Field	Lease	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Bibliography References
Texas	Strawn	Katz	Katz	10 to 15	10 to 15	5 to 10	15 to 20	10 to 15	5 to 10	70
Oklahoma	Morrow	Postle	Postle	10 to 15	10 to 15	5 to 10	15 to 20	10 to 15	1 to 5	71,72
Oklahoma	Morrow	Camrick	Camrick	10 to 15	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	
Texas	Delaware Ramsey	Twofreds	Twofreds	10 to 15	10 to 15	5 to 10	15 to 20	10 to 15	5 to 10	73,74,75
Texas	Delaware Ramsey	Ford Geraldine	Ford Geraldine	10 to 15	10 to 15	5 to 10	15 to 20	10 to 15	5 to 10	76,77
Texas	Delaware Ramsey	El Mar	El Mar	10 to 15	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	
Texas	Delaware Ramsey	East Ford	East Ford	10 to 15	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	
Texas	Springer	Northeast Purdy	Northeast Purdy	10 to 15	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	78
Texas	Marmaton	Hansford Marmaton	Hansford Marmaton	10 to 15	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	79
Texas	Yates	North Ward Estes	North Ward Estes	5 to 10	10 to 15	1 to 5	10 to 15	10 to 15	1 to 5	80
California	Stevens MMB	Elk Hills	Elk Hills MMB	10 to 20	10 to 15	5 to 10	20 to 30	10 to 15	5 to 10	81

Table 7. -Tensleep, Mesaverde Almond, Weber, Sprayberry (Fractured Sandstone)

				Current Economic			Life beyond 80% HCPV Inj			
State	Formation	Field	Lease	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Bibliography References
Wyoming	Tensleep	Wertz	Wertz	5 to 10	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	82
Wyoming	Tensleep	Lost Soldier	Lost Soldier	5 to 10	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	83 thru 86
Wyoming	Mesaverde Almond	Patrick Draw Monell	Patrick Draw Monell	5 to 10	10 to 15	5 to 10	10 to 15	10 to 15	5 to 10	
Colorado	Weber SS	Rangely	Rangely Weber Unit	5 to 10	5 to 10	1 to 5	10 to 15	5 to 10	1 to 5	87 thru 92
Texas	Sprayberry	Sprayberry	Sprayberry	0 to 2	10 to 15	5 to 10	0 to 2	10 to 15	5 to 10	93,94

Table 8. - Heavy Oil

				Current Economic			Life beyond 80% HCPV Inj			
State	Formation	Field	Lease	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Tertiary Recovery (%OOIP)	Gross CO_2 Utilization (MSCF/STB)	Net CO_2 Utilization (MSCF/STB)	Bibliography References
California	Ranger	Wilmington (Onshore)	FB1, FB3, FB5	10 to 15	15 to 20	5 to 10	10 to 15	15 to 20	5 to 10	95 thru 98
Arkansas	Ozan (Meaken Sand)	Lick Creek	Lick Creek Unit	10 to 15	15 to 20	5 to 10	10 to 15	15 to 20	5 to 10	99, 100

Conclusion

With more than thirty-eight years of successful enhanced oil recovery (EOR) projects in the Permian Basin (Texas), Mississippi, Wyoming, Colorado, California, Oklahoma, and several countries worldwide, carbon dioxide CO_2 flooding is a proven method for extending field life. CO_2 acts as a solvent to overcome forces that trap oil in tiny rock pores, helping sweep immobile oil left after primary or secondary recovery operations. Generally, CO_2 is not miscible at first contact with reservoir oils, but miscibility can be developed in reservoirs above or near the Minimum Miscibility Pressure (MMP). CO_2 can attain miscibility through a multiple-contact process that vaporizes or extracts both intermediate and higher molecular weight hydrocarbons from the reservoir oil. The CO_2 phase picks up many intermediate hydrocarbon components from the oil, swells the oil, and reduces oil viscosity, making it mobile to move through the rock.

Advances in technology and reservoir understanding have made detailed evaluation of potential EOR candidates obtainable within months, not years. In addition, improved reservoir management and innovative investment plans have significantly reduced risks and increased rewards. Many of the original questions about CO_2 flooding involved the displacement efficiency of the process, how CO_2 would interact with the oil, and how much oil could be recovered. Many of these questions have been answered with better reservoir management tools. Not all fields are good candidates for CO_2 Tertiary Recovery. A reservoir must contain certain characteristics for a CO_2 flood to be successful. In the past, it was thought the oil must be found at depths sufficient to allow for high pressures, so that CO_2 and oil develop total miscibility. This is not necessary correct. Most CO_2 floods operate at reservoir pressures that are above their minimum miscibility pressure. But today, it is not uncommon to find CO_2 projects that operate below or near the minimum miscibility pressure. The CO_2 still produces tertiary oil. The process is not as efficient as that operated above the minimum miscibility pressure. Most historical CO_2 floods have targeted reservoirs that have a gravity of 25 API units or greater, but low API Gravity reservoirs are also targets. For example: Wilmington field in California produces 14 API Gravity crude from the Ranger formation. Three pilots were conducted in Fault Blocks I, III, and V. Eventhough economic performance was reported poor, mostly due to an inadequate CO_2 source and low oil price enviornment, a good number of wells increased oil rate from 30 BOPD to over 300 BOPD after CO_2 was injected. CO_2 has the ability to affect the full C_2 through C_{30+} compositional range. Whereas, Nitrogen, and in some cases flue gas injection, will only extract the lighter components (C_2 through C_6). In addition, a high percentage of intermediate hydrocarbons in the oil composition can be beneficial in making the overall recovery process more efficient. If these occur naturally in the oil, then the oil will probably contain a low value of Minimum Miscibility Pressure (MMP). If the oil has a high MMP, then additions such as propane, butane, condensate, or other types of hydrocarbons can be added to the CO_2 injection stream to lower the minimum miscibility pressure and improve overall oil recovery.

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