

CMTC-502866-MS

Enhanced Oil Recovery – The History of CO₂ Conventional WAG Injection techniques developed from Lab in the 1950's to 2017

David Merchant, Merchant Consulting

Copyright 2017, Carbon Management Technology Conference

This paper was prepared for presentation at the Carbon Management Technology Conference held in Houston, Texas, USA, 17–19 July 2017.

This paper was selected for presentation by a CMTC program committee following review of information contained in an abstract submitted by the author(s). Contents of the paper have not been reviewed and are subject to correction by the author(s). The material does not necessarily reflect any position of the Carbon Management Technology Conference, its officers, or members. Electronic reproduction, distribution, or storage of any part of this paper without the written consent of the Carbon Management Technology Conference is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of CMTC copyright.

Abstract

During the past 45 years, CO₂ 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 CO₂ 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 CO₂ flood for long term profit. The purpose of this report is to help disseminate this knowledge to operating companies interested in EOR flooding or to CO₂ Sequestration Communities interested in storing CO₂ in EOR projects.

In 2015, Merchant Consulting published CMTC-440075-MS “Life beyond 80 – A look at Conventional WAG Recovery beyond 80% HCPV Injection in CO₂ Tertiary Floods”. The primary objective of the report was to target all 10 CO₂ Recovery Methods used today including “Conventional WAG Techniques” which have been used in over 90% of all the Enhanced Oil Recovery projects implemented to date. These include projects in the Permian Basin in Texas, Colorado, Oklahoma, and Wyoming. The paper presents answers to the question “What is life after 80% HCPV Injected?” And “What effect does life after 80% HCPV have on Tertiary Oil Recovery, CO₂ Utilization and CO₂ 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.

Conventional WAG History in CO₂ Tertiary Oil Projects:

To achieve CO₂ Injection beyond 80% HCPV Injection requires proper CO₂ WAG Management. The purpose of this report is to provide both the EOR and CO₂ Sequestration Communities an understanding of the “History of Conventional WAG” and how it has changed from first introduced in the Lab in the 1950's, to how it was implemented and developed in the 1980's by the Major Oil Companies in the Permian Basin, and how Conventional WAG is being managed today in the field.

CO₂ Flood History

EXPANDING AND NEW MARKETS

Rocky Mtn. (Expanding)

Tertiary Oil Recovery in the New Millennium

Great Plains Coal Plant

Mid-Century / East (New)

LaBarge

Sheep Mountain

McElroy Dome

Permian Basin (Expanding)

California (New)

Sacro Field - 1972

Gulf Coast (New)

Mississippi (Expanding)

2010's

Ford	State	Resource	Strategy	SNOW Rejected	Rec'd, NODD	Utilization, %	Grass Area M2
Parkville							
DeLande	Texas	Denton	Drop Out	30	34		
DeLande	Texas	Denton	Drop Out	30	34	81.6	
San Joseville	Texas	Denton	Drop Out	30	28		
Albion	Texas	Denton	Drop Out	30	28		
Albion	Texas	Denton	Drop Out	30	28	81.6	
North Cross	Texas	San Antonio	Drop Out	40	22	58	
North Pearl	Alabama	Springer	Sandstone	30	73	6.5	
Alanya	Colorado	Wheat	Sandstone	30	73	6.5	
San Joseville	Texas	Cayahaba	Colombia	30	73	6.5	
San Joseville	Texas	Cayahaba	Colombia	30	68	9.5	
San Joseville	Texas	Cayahaba	Colombia	30	76	14	
Two Hills	Texas	Denton	Sandstone	40	25.6	5.6	
Waco	Washington	Sandstone	Sandstone	40	28	10	

7% to 12% OOIP Rec
30% to 40% HCPV Inj

Tapered WAG Injection

WAG (lb) vs Time (min)

250
200
150
100
50
0

Time (min)

0 10 20 30 40 50 60 70 80 90 100

Tapered WAG
Level Load

BOP (lb) vs (20, 30, 50, 70, 90) - NBP (psi)

250
200
150
100
50
0

NBP (psi)

20 30 50 70 90

Tapered WAG
Level Load

Level Load

WAG (lb) vs Time (min)

250
200
150
100
50
0

Time (min)

0 10 20 30 40 50 60 70 80 90 100

Level Load
Tapered WAG

BOP (lb) vs (20, 30, 50, 70, 90) - NBP (psi)

250
200
150
100
50
0

NBP (psi)

20 30 50 70 90

Level Load
Tapered WAG

Advantages

1. Increased Safety (Reduce Gas Processing)
2. Improved Operations (Less Gas Control)
3. Reduce Gas and Pressure (BOP, NBP, etc.)
4. Can control the fluid to Part and Plunger Setting
5. Can accelerate or retard Plunger Response

Disadvantages

1. None to date

18% OOIP Rec
80% HCPV Inj

20% to 26% OOIP Rec
140% to 190% HCPV Inj

Note: Not all fields will achieve this

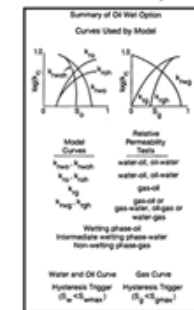
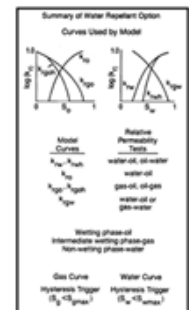
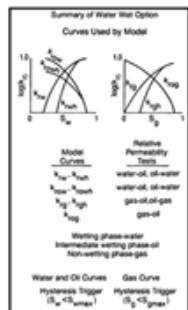
The reason why CO₂ works is simple. The CO₂ acts as a solvent when injected into the reservoir and swells the Residual Oil (oil left after water flood) and reduces its viscosity. This causes the Residual Oil to swell and become mobile and be produced.

A schematic diagram showing a cross-section of a reservoir. A yellow rectangular region on the left is labeled "CO2 Rich (Slug)". An arrow points from this region towards a green oval region labeled "Oil Bank". To the right of the "Oil Bank" is a dark green region labeled "Residual Oil".

Multiple Contact Miscible Process
(time and compositionally dependent)

Miscible Zone formed by CO_2 becoming enriched with $\text{C}_3 - \text{C}_{30}$

Oil Wet – Dolomites, Limestone



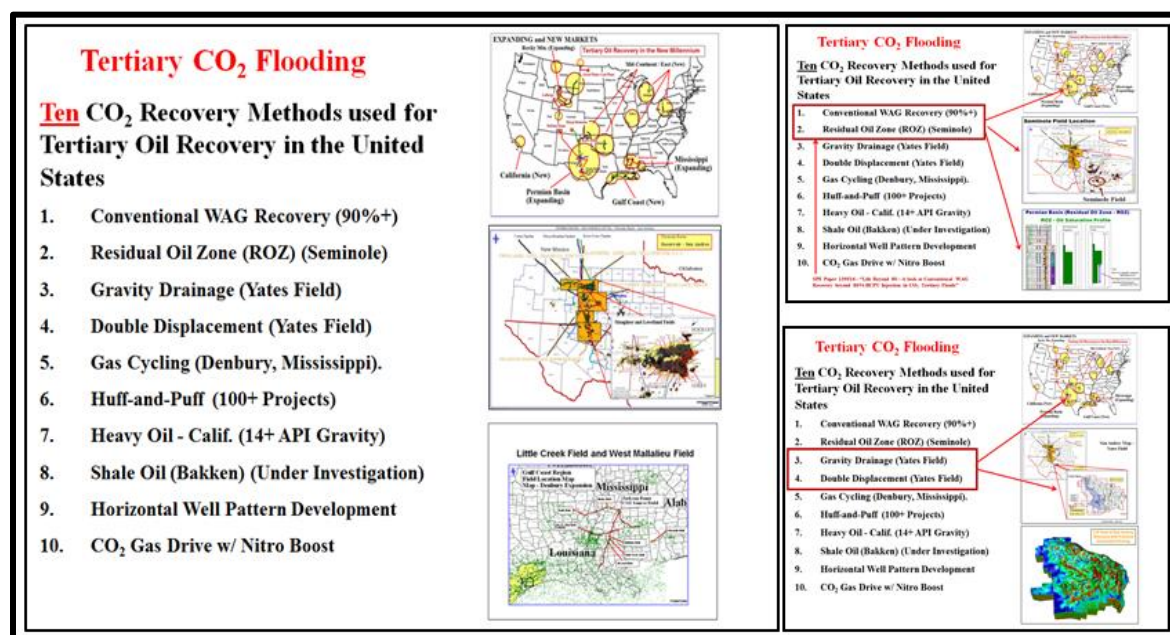
Note: Tertiary Oil Recovery and CO₂ trapping is governed by Relative Permeability Hysteresis of the non-wetting phase.

The amount of Tertiary Oil Recovered and the amount of CO₂ Trapped or Sequestered is dependent on the rock type. In addition to mobilizing residual oil saturation, a portion of the CO₂ becomes trapped. In the Petrophysical world, this is known as Relative Permeability Hysteresis or Trapping of the Non-wetting Phase. In this case CO₂ is the non-wetting phase. As demonstrated above, this phenomenon occurs in Water Wet Rocks (Sandstones), Intermediate Wet Rocks (Sandstones or Carbonates), and in Oil Wet Rocks (Dolomites and Limestone formations).

CO₂ Tertiary Recovery Methods

Introduction

CO₂ Tertiary Recovery Processes to date encompass “**Ten**” Recovery Methods. Four of these methods are used in the Permian Basin. Conventional WAG Techniques have been used in over 90+% of the CO₂ floods around the World. The Seminole field example presented in this report is an example of a field operated under Conventional WAG that targets both the Main Pay and ROZ zones.



Additional information can be found: SPE Paper 139516 or CMTC-502866-MS (“Life Beyond 80 – A look at Conventional WAG Recovery beyond 80% HCPV Injection in CO₂ Tertiary Floods”)

Carbon Sequestration Options: **Ten** Recovery Methods for EOR

Most Enhanced Oil Recovery Projects use one of the following **ten** operating methods: Conventional WAG Recovery, ROZ Recovery, Gravity-stabilized Recovery, Double Displacement, Gas-cycling Huff-and-Puff, Heavy Oil-California, Shale Oil (Bakken, Wolfcamp), Horizontal Well Pattern Development, and CO₂ Gas Drive w/ Nitro Boost. The primary difference between methods depends on the reservoir geology and well pattern configuration. In Conventional CO₂ 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 CO₂ flood response. In conventional WAG operations, the objective is to minimize the amount of CO₂ purchased (CO₂ stored in Sequestration projects), which is typically in the range of range of 30%-50% of the total HCPV CO₂ injected. In un-conventional Gravity-Stabilized and Double Displacement case histories, Flue Gas, CO₂, Lean Gas or N₂ is usually injected in the top of the structure and oil is produced from the bottom. More CO₂ can be sequestered than conventional WAG operations. As much as 80% of the total pore volume can be displaced with CO₂. In Gas-cycling projects, typical of projects operated by Denbury in Mississippi, CO₂ is cycled through the formation. As much as 6 pore-volumes of CO₂ are injected to recover 18% OOIP. In Huff-and-Puff operations, the CO₂ 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 CO₂ and tertiary oil back. In California the Wilmington field had three CO₂ pilots in 14 API Gravity Crude. Recovery was comparable with West Texas Operations. Shale Oil with CO₂ is still under investigation. Horizontal Well CO₂ floods are operational in Aneth field in Utah and Weyburn field in Canada. The Gravity Drainage case with added Nitro-Boost was developed for rate acceleration cases where nitrogen follows CO₂ Injection.

CO₂ Storage - Mis-conceptions about EOR

Over the years, there have been many mis-conceptions and half truths developed about EOR and its ability to store CO₂.

The **first mis-conception** about CO₂ flooding deals with ranges of Tertiary Oil Recovery reported over the years. In the 1990's, most all of the major oil companies reported tertiary oil recovery in the range of 10%-12% OOIP with a 30%-40% HCPV CO₂ slug size. By 2000, this number grew to 18% OOIP recovery with an 80% slug size. Today, expected recoveries in certain fields are expected to exceed 26% OOIP with 190% HCPV CO₂ injected. However, NOT all fields will achieve this level of oil recovery. Each CO₂ project must be judged on its own merits.

The **second mis-conception** about CO₂ flooding deals with the amount of CO₂ Storage in EOR operations. Normal EOR operations have always stored or trapped CO₂ in the reservoir. Tertiary recovery is a displacement process. For the EOR process to work, CO₂ must be cycled through the reservoir, similar to water flood operations. The CO₂ acts as a solvent to swell the remaining oil left after water flood and decreases the oil's viscosity; thus, allowing the tertiary oil to flow. Three phase relative permeability dictates the amount of CO₂ trapped in the formation due to phase trapping. From existing CO₂ flood evaluations, this equates to the amount of CO₂ purchased and represents approximately 30%-40% of the Hydrocarbon-Pore-Volume. With extended WAG with CO₂ volumes exceeding 125% HCPV, the storage capacity could increase to 50%-60% HCPV, but involves large volumes of CO₂ through-put with little incremental gain in oil recovery.

The **third mis-conception** deals with throughput Injection Rate and Injection Pressure (Water Injection or CO₂ Injection). All reservoirs have a Maximum Through-put Rate that can be injected into the reservoir. The maximum amounts of CO₂ that can be stored in a reservoir are based on a number of factors. These include: The total number of production and injection wells available, pattern configuration, current reservoir pressure, fracture pressure, injection flow capacity (permeability-thickness (kh) of each injection well), and relative permeability. Most water flood operations operate at or near fracture pressure. The same is true for CO₂ floods. The objective is to provide maximum CO₂ throughput rate across the reservoir at a level that maintains good seal integrity.

The **fourth mis-conception** about CO₂ flooding deals with the Total CO₂ Storage Capacity of a reservoir. To date, all CO₂ floods operate with the intent to minimize the amount of CO₂ purchased. Under these conditions, CO₂ is purchased up-front and cycled through the reservoir until the revenue from the oil and hc-gas production doesn't have the ability to support the cost to recover the oil (abandonment). This date has been very elusive to determine. Of all the CO₂ projects operated to date, most are still operating today. A limited few projects have been shut-in due to a low oil price environment, but could be returned back to production if given the right economic conditions.

The **fifth mis-conception** about CO₂ flooding deals with CO₂ Storage Timing. Is it at the beginning? Does it occur during EOR CO₂ operations? Or, is it at the end of EOR operations? For those advocating a switch from EOR to CO₂ Storage two-thirds though or near the end of the EOR project should think through the physics. You can't fool Mother Nature. The amount of CO₂ **TRAPPED, STORED, OR SEQUESTERED** is dependent on the Composition of the Residual Oil Saturation and Phase Trapping of the Non-Wetting Phase, which occurs throughout the life of CO₂ injection, with 75% of CO₂ storage occurring during the first one-third of the project's life. After this initial period, most of the CO₂ that is injected is re-cycle CO₂ from the CO₂ recovery plant. CO₂ purchases near the end of the life of an EOR project are minimal.

The **last mis-conception** deals with achieving Total CO₂ Storage Potential of the reservoir. Currently there are ten methods used by the industry to recover oil with CO₂. All target the remaining tertiary oil. None target the **water**. The Eleventh Recovery Method which targets CO₂ storage removes both the **CO₂** and **Water** from the reservoir. In a World where there is an infinite amount of CO₂ available for storage, the remaining water in the reservoir becomes a commodity target along with the oil. Under this scenario, the objective will be to displace as much of the remaining oil plus water from the reservoir and replace it with CO₂. Since seal integrity will always be maintained below formation parting fracture pressure, the additional storage capacity provided by removing both the oil and water would far exceed EOR storage operations alone.

Conventional WAG Techniques

Conventional WAG Techniques have been used in over 90% of the CO₂ Floods implemented today. They are designed to work well in reservoirs that are developed on pattern spacing. These include: Five-spot, Nine-spot, and Chickenwire pattern development. The objective is to “Level Load” produced gas production to a CO₂ Recovery Plant inlet gas rate, which extends field life and recovers more tertiary oil.

What is Conventional WAG Management?

Conventional WAG Injection Techniques

DIFFERENT OPERATORS

DIFFERENT PHILOSOPHIES (Reservoir Driven)

- Continuous CO₂ - Continuously inject CO₂ (No water)
- Constant WAG - example - 1:1 WAG with (1.0 % CO₂, 1.0% H₂O)
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 % CO₂, 0.10 % H₂O) for 5% HCPV
WAG (1.0 % CO₂, 0.50 % H₂O) for 10% HCPV
WAG (1.0 % CO₂, 1.00 % H₂O) for 20% HCPV
WAG (1.0 % CO₂, 2.00 % H₂O) for 30% HCPV
Chase Water Injection

“Wetting the WAG”

Note: Total Slug Size = 85% HCPV Inj. Of CO₂

Today, most operators have adopted the Tapered WAG approach to optimize WAG management.

Conventional WAG Recovery

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

1. Continuous CO₂ Injection
2. Constant WAG Injection
3. Tapered or Hybrid WAG Injection
4. Simultaneous CO₂ Injection (Limited use)

What is WAG Management?

Through the 1980’s and 1990’s, Amoco, Shell, Arco, Exxon, Mobil, and Texaco committed significant manpower to evaluate the feasibility of full field scale CO₂ 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 CO₂ flooding process. The results are presented below.

All Conventional WAG Injection Projects have one thing in common. CO₂ is injected into the reservoir and the produced recycle CO₂ 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 CO₂ to decrease solvent mobility^{Turek, 1,102}. As CO₂ 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 1990’s, Tapered and Hybrid WAG Operations were adopted to improve the overall recovery process^{2,3,4,5, 6,104,105}. During the WAG process, CO₂ and Water are injected into the reservoir in alternating CO₂ and water slug sizes time periods. For Constant WAG operating schemes, the half cycle slug size is typically fixed for example at 1.0% HCPV CO₂ for the Gas Cycle and 1.0% H₂O for water. For Tapered WAG projects, WAG Ratios change with time. “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 improve overall conformance or adjusted to “Level Load” gas production to a Plant inlet rate.

Conventional WAG History

Lab Experiments in the 1950's and 1960's

Conventional Water-Alternating-Gas (WAG) was originally discovered in the 1950's when Caudle and Dyes introduced water in Lab experiments to decrease gas mobility. During the 1960's over 150 small scale Miscible and Immiscible projects were implemented across the United States by labs and oil companies interested in developing Enhanced Oil Recovery for additional recovery of oil beyond Waterflood operations.

Permian and Rocky Mountain Basins History of "WAG"

1950's and 1960's

1950's – 150 Small Scale Miscible and Immiscible Projects
1958 - Lab Experiments Caudle and Dyes introduced water to decrease solvent mobility

1970's

1972 – Sacroc Unit (Kelly Snyder field) First Commercial Large Scale Project
1972-1979 North Cross, Two Feds, Maljamar, others

1980's Large Scale Permian Basin and Rocky Mountain Expansions

Slaughter field three projects plus Wasson ODC Unit – Amoco's Tapered WAG
Wasson field Denver Unit – Shell's Continuous Injection area plus DUWAG
Wasson field Willard Unit – Arco's Area Wide WAG went to Individual Patterns
Seminole field – Amerada Hess's Constant WAG scheme
Rangely field – Chevron's Wide Area WAG scheme
Baird (Lost Soldier and Wertz field) – Amoco's Tapered WAG

1990's, 2000's, and 2010's

Most new CO₂ flood projects adopt the "Tapered WAG" approach to WAG Management

SPE 18977 (1989), Table 1

Field	State	Reservoir	Lithology	%HCPV Injected	Rec Eff, % OOIP	Gross Utilization, Mcf/Bbl	Net Utilization, Mcf/Bbl
Field Scale							
Dollarhide	Texas	Devonian	Trip Chert	30	14		2.4
East Vacuum	Texas	San Andres	Oolitic Dolomite	30	8	11.1	6.3
Ford Geraldine	Texas	Delaware	Sandstone	30	17	9	5
Means	Texas	San Andres	Dolomite	55	7.1	15.2	11
North Cross	Texas	Devonian	Trip Chert	40	22	18	7.8
Northeast Purdy	Oklahoma	Springer	Sandstone	30	7.5	6.5	4.6
Rangely	Colorado	Weber	Sandstone	30	7.5	9.2	5
Sacroc (17 Pattern)	Texas	Canyon Reef	Carbonate	30	7.5	9.7	6.5
Sacroc (4 Pattern)	Texas	Canyon Reef	Carbonate	30	9.8	9.5	3.2
South Welch	Texas	San Andres	Dolomite	25	7.6		
Two Feds	Texas	Delaware	Sandstone	40	15.6	15.6	8
Wertz	Wyoming	Tensleep	Sandstone	60	10	13	10

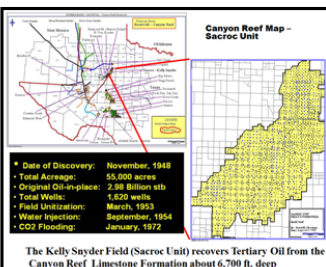
SPE 18977 Brock and Bryon 1989

CO₂ Flooding in 1970's

First Commercial Scale CO₂ Flooding in 1970's

Chevron, who operated the Sacroc Unit in the Permian Basin, was the first field to inject CO₂ as a commercial project in 1972. Chevron injected CO₂ over the total unit with less than 15% in any one pattern and sold the property in 1992 to Pennzoil. Pennzoil ramped up CO₂ Injection and implemented a 300 acre pilot in the middle of the field of which 1/3 of the total field's production out of 55,000 acres was being produced from the pilot area. In 1998, Pennzoil sold the field to Devon and Devon then sold the field to Kinder Morgan in 2000. Kinder Morgan then ramped-up CO₂ injection to over 900 MMSCFIPD. The result was a Tertiary oil response growth from 9,600 BOPD to over 30,000 BOPD.

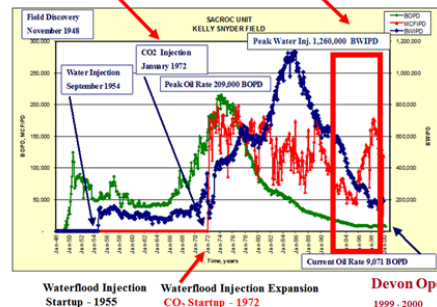
Permian Basin - 1970's to 2017 "First Commercial CO₂ Flood - 1972" Sacroc Unit in Kelly Snyder Field



Sacroc Unit – Historical Performance

Chevron Ownership Pennzoil Operatorship

First Commercial CO₂ flood in 1972 1992 - 1999



Kinder Morgan Operatorship
2000 to Present

Over the course of CO₂ Tertiary History, the Sacroc Unit has had several operators over time

Chevron should be commended for implementing the first Commercial CO₂ flood in 1972

Pennzoil and Devon operated in the 1990's, but lacked the capital to make large scale investments

Kinder Morgan which in 2003 ramped up CO₂ Purchases bringing oil production to 30,000 BOPD in 2017

Chevron should be commended for implementing the first Commercial CO₂ flood in the United States, but only sprinkled CO₂ over the total reservoir limit.

Sacroc Unit – Historical Performance

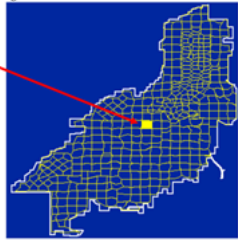
Pennzoil Operatorship (1992-1998)

Sacroc Unit – Pennzoil Ownership Center-line Project

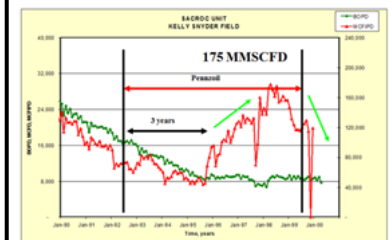
1996 CO₂ Pattern Development Plan
300 Acre Pilot

Pennzoil Team

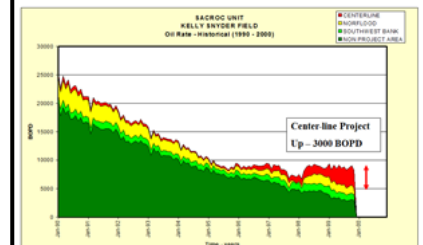
1. Dr. Ghassan Bayat
2. Tony Beavengau
3. Claud Pickard
4. Jack Horkowitz
5. Tom Wiegate
6. Don Hartman



Sacroc Unit – Pennzoil Ownership Historical Production – Oil Production and CO₂ Injection



Sacroc Unit – Pennzoil Ownership Historical Production by Project Area



Chevron should be commended for being the first Commercial CO₂ flood, but over the course of time sprinkled CO₂ into the Reservoir.

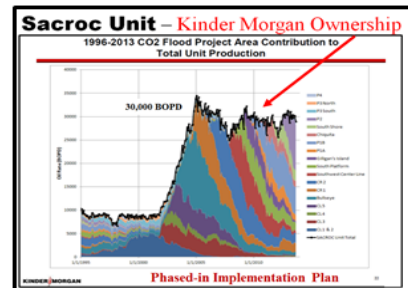
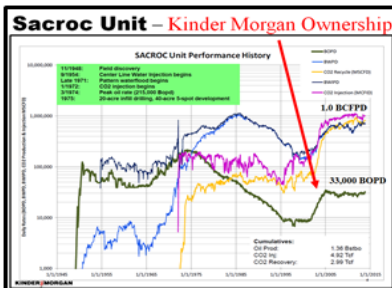
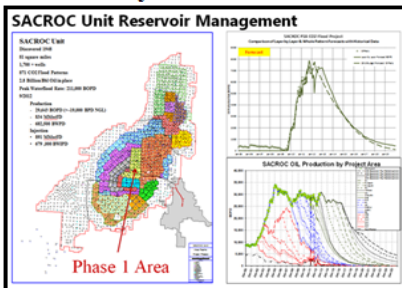
Pennzoil implemented a 300 acre Centerline Pilot Project in 1996 which produced 1/3 of the total field's production over the total 55,000 acre unit boundary

Pennzoil in 1996 implemented a 300 acre Centerline Pilot Project which produced one third of the fields 9,600 BOPD production. (Ref: 106) In 1998, Pennzoil sold the field to Devon who later sold the field to Kinder Morgan in 2000.

Sacroc Unit – Historical Performance

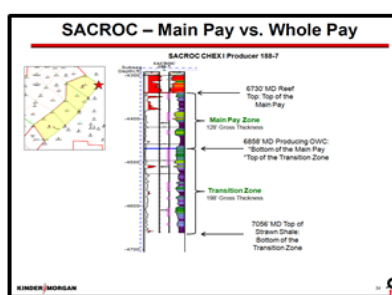
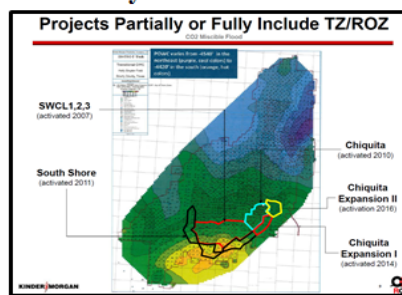
Kinder Morgan Operatorship (2000 -Present)

Main Pay Zone



Kinder Morgan implemented a phased-in Tertiary Development Plan and expanded CO₂ Injection to over 1,000 MMSCFIPD which resulted in a 30,000 BOPD Response still seen in 2017. WAG Management is on an Individual Pattern Basis with Multiple Pattern Development programs developed over time

ROZ Pay Zone



Conclusions

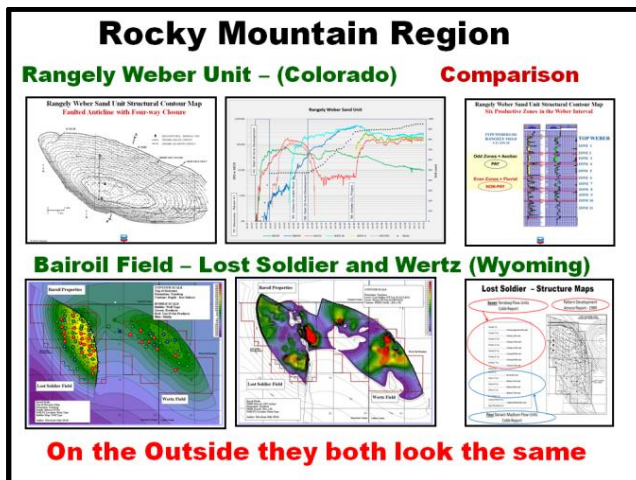
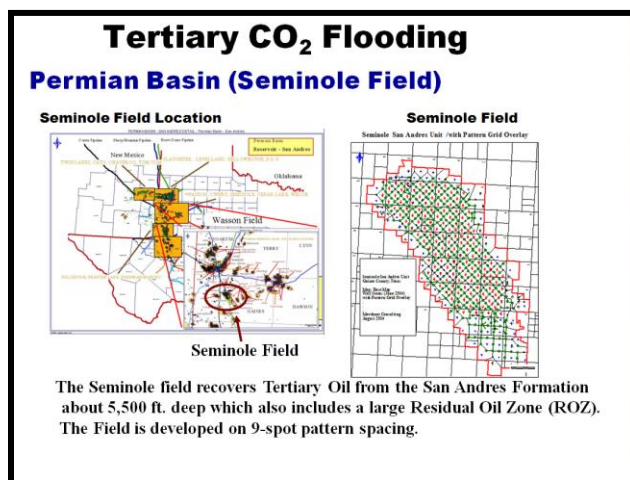
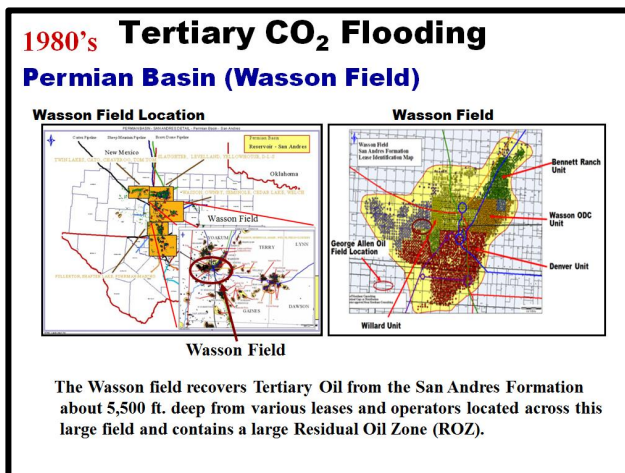
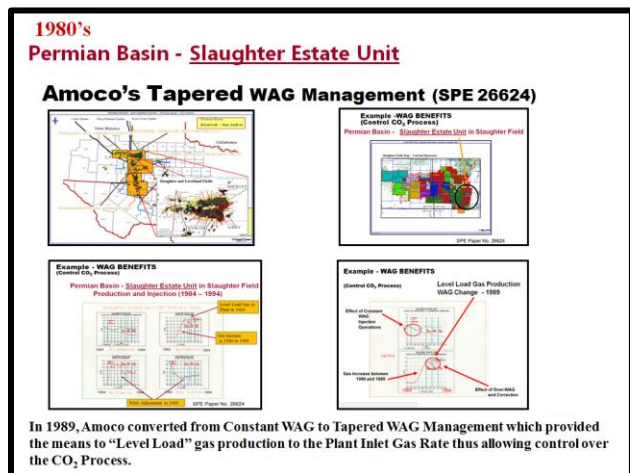
- TZ/ROZ is highly responsive to miscible CO₂ flooding
- TZ/ROZ not targeted in primary and secondary recovery
- TZ/ROZ oil saturation similar to or better than main pay after water flooding
- Multiple TZ/ROZ projects now have repeatedly shown favorable performance
- Even in areas with long production histories there is still potential to find more

Kinder Morgan has also targeted the Residual Oil Zone below the Main Pay Zone. Multiple TZ/ROZ projects have repeatedly shown favorable performance

In 2000, Kinder Morgan implemented a multi-phase Tertiary Development Plan that increased CO₂ Injection to over 800 MMSCFIPD, which resulted in a 30,000 BOPD Response still seen in 2017.

CO₂ Flooding in 1980's

In the 1980's, major oil companies including Shell, Amoco, Texaco, Arco, Phillips, Oxy, and Exxon implemented CO₂ projects in many of the large fields located across the Permian Basin, Rockies, and Gulf Coast Regions. As reported by the major oil companies, expected tertiary recovery was typically in the 8% to 12% OOIP range. Optimum slug size for most projects was projected to be in the 30% to 40% HCPV CO₂ injection range.



In the 1980's, Major Oil Companies also implemented different types of CO₂ Recovery Methods to both experiment and determine which process works best. Each will be discussed below.

Permian and Rocky Mountain Basins History of "WAG"

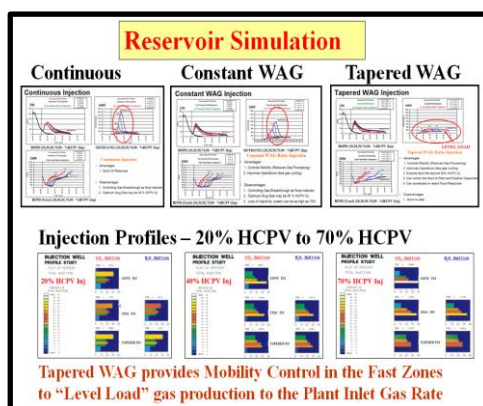
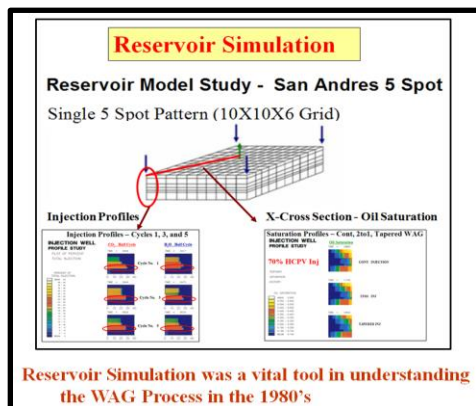
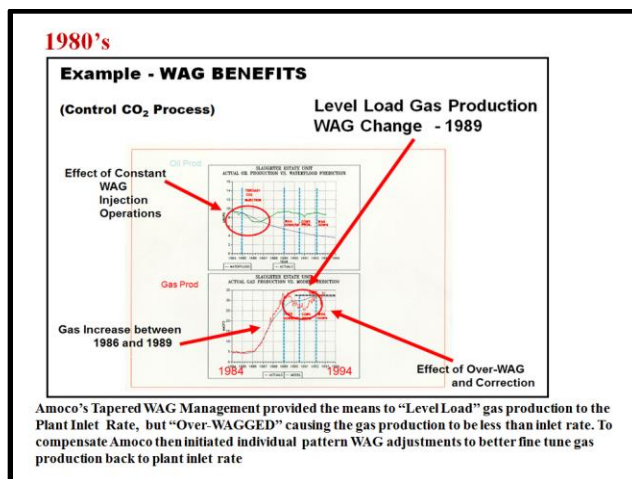
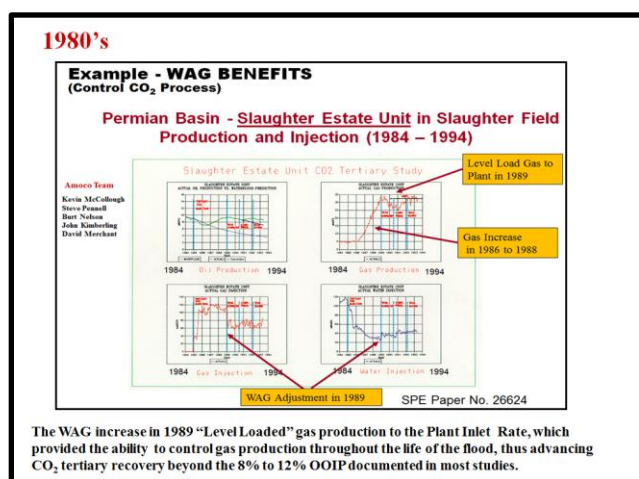
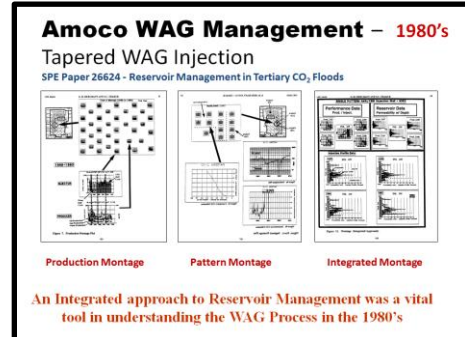
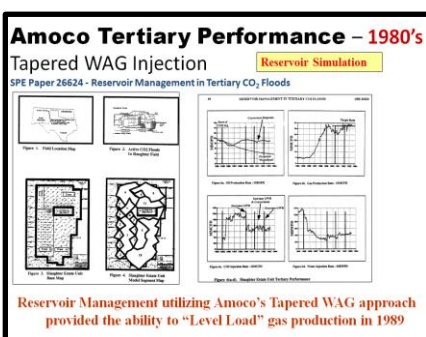
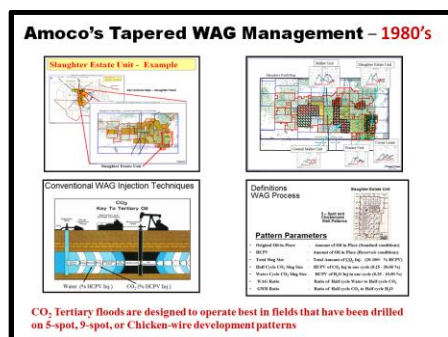
1980's Large Scale Permian Basin and Rocky Mountain Expansions

Slaughter field three projects plus Wasson ODC Unit – Amoco's Tapered WAG
Wasson field Denver Unit – Shell's Continuous Injection area plus DUWAG
Wasson field Willard Unit - Arco's Area Wide WAG went to Individual Patterns
Seminole field – Amerada Hess's Constant WAG scheme
Rangely field – Chevron's Wide Area WAG scheme
Bairoil (Lost Soldier and Wertz field) – Amoco's Tapered WAG

CO₂ Flooding in 1980's (Amoco – Tapered WAG)

Amoco initiated CO₂ injection into four floods in the mid 1980's. These included: Slaughter Estate Unit, Central Mallet Unit, and Frazier Unit in Slaughter field plus Wasson ODC in Wasson field. All initially were operated under a constant WAG. During this time frame, extensive modelling was conducted to determine a method that could optimize the WAG process and extend oil recovery. (Ref: 107) The result was "Tapered WAG" which provided the means to "Level Load" total gas production from the field to a maximum "Plant Inlet Gas Rate". In 1989, Amoco implemented this new technology into all four projects, achieving total success.

As this technology improved, advancements in CO₂ flood design have been implemented into more improved reservoir management practices. In the 1990's, Constant WAG was being replaced with Tapered WAG operations and tertiary oil recovery increased to 18% of a field's Original Oil-in-Place. Today, most fields implemented during the 1980's have surpassed the 40% HCPV injection, advancing to or passing earlier HCPV CO₂ predictions.

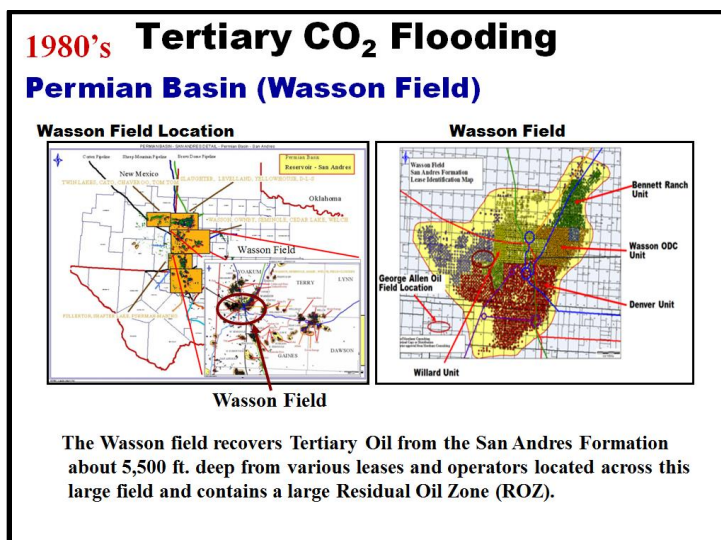


Slaughter Field
Bibliography References: 19 thru 29

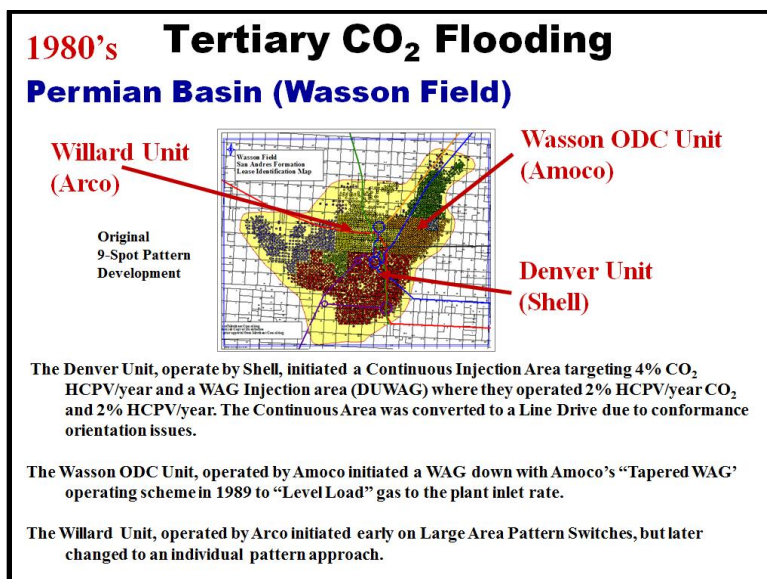
“Tapered WAG Management” can provide Reservoir Engineers with a “Reservoir Management Tool” that can properly manage WAG, but only through proper “Reservoir Management Practices”

CO₂ Flooding in 1980's Wasson Field (Shell, Arco, and Amoco)

Shell, in the Denver Unit of Wasson field took a different approach to understanding CO₂ management. It first divided the Denver Unit up into three project areas. The main area was a Continuous Injection project where they targeted 4% HCPV/per year, the second project area was a Constant WAG injection area (DUWAG Area) where they targeted 2% HCPV/per year CO₂ and 2% HCPV/per year Water. The final injection area in the western part of the unit was poorer quality reservoir and remnants of a gas cap. As technology improved, advancements in CO₂ flood design were implemented into reservoir management practices by Shell through the 1990's. The nine-spot inverted line drive configuration was changed to more of a direct line drive after conformance issues were identified in the field based on performance and pattern adjustments could better control conformance issues.



Arco, in the Willard Unit first implemented an area wide switching program based on making large area switches. The reservoir responded with some injectors taking 4% HCPV where others may have had 1% HCPV injected. Due to pattern imbalance issues, Arco then switched to an individual pattern WAG management program.

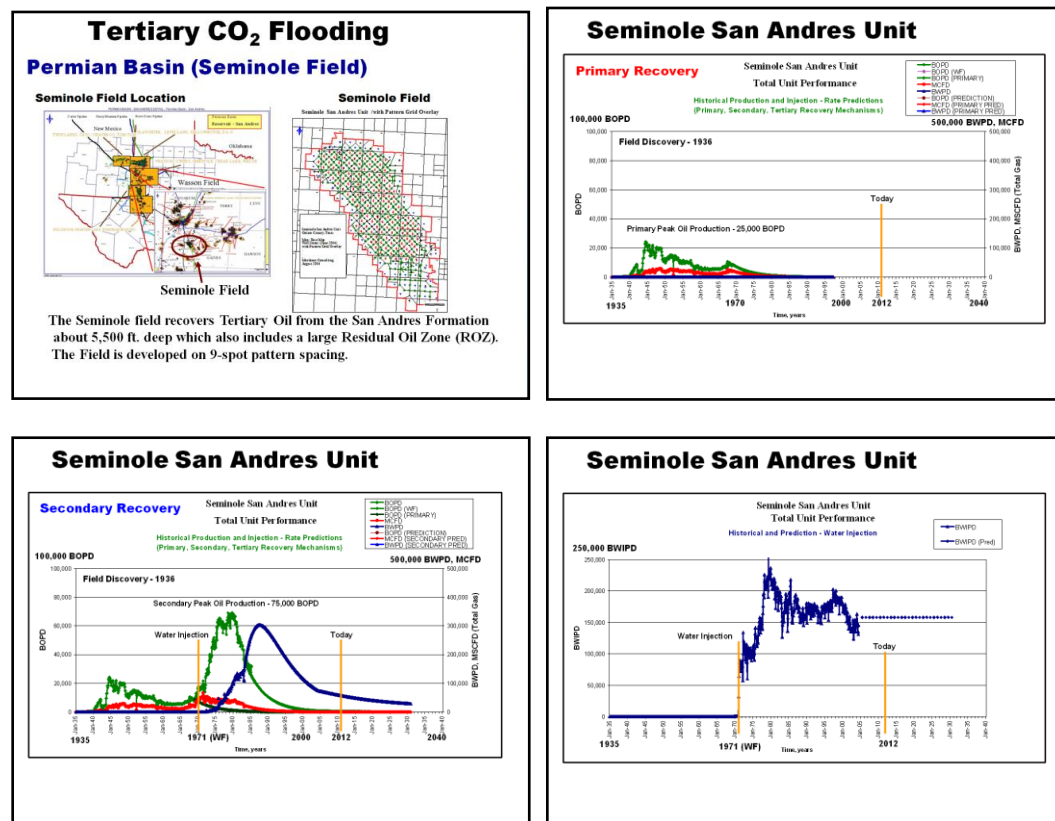


Amoco, in 1989, at the same they implemented Tapered WAG in Slaughter field, implemented a Tapered WAG at Wasson ODC Unit to "Level Load" gas production to its Ryan Holmes Plant Gas Rate Limit. As a result, the benefit of modifying to a Tapered WAG extended Tertiary Oil Recovery way beyond all of Amoco's original model predictions.

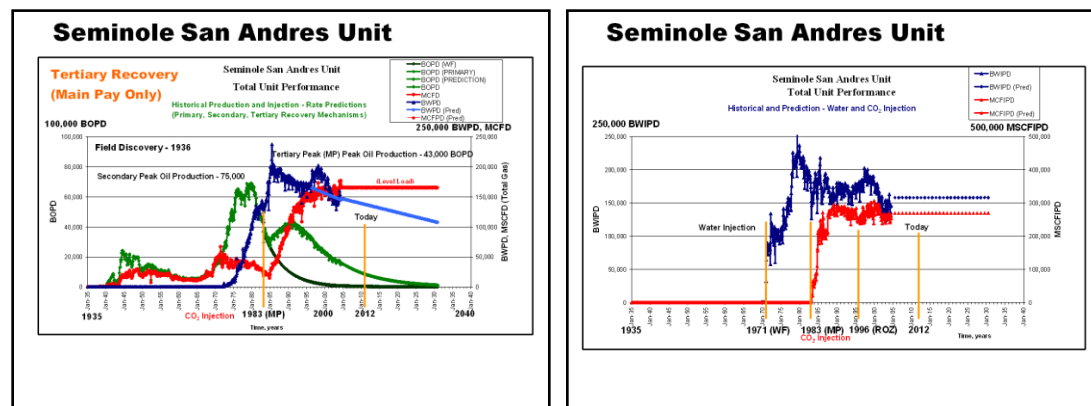
CO₂ Flooding in 1980's (Amerada Hess – Seminole San Andres Unit – Constant WAG)

The best example of CO₂ Tertiary Recovery is the Seminole San Andres Unit in the Permian Basin. The field has undergone Primary, Secondary Waterflood, CO₂ Tertiary operations in the Main Pay, and in 1996 initiated CO₂ Tertiary operations in the Residual Oil Zone (ROZ).

The Seminole field was discovered in 1936 with **water injection operations** initiated in 1971. Under Primary Recovery the field would have only recovered 12.8% of its Original Oil-in-Place (OOIP). With Secondary Water flood operations, the field would have recovered 42.7% of its Original Oil-in-Place.



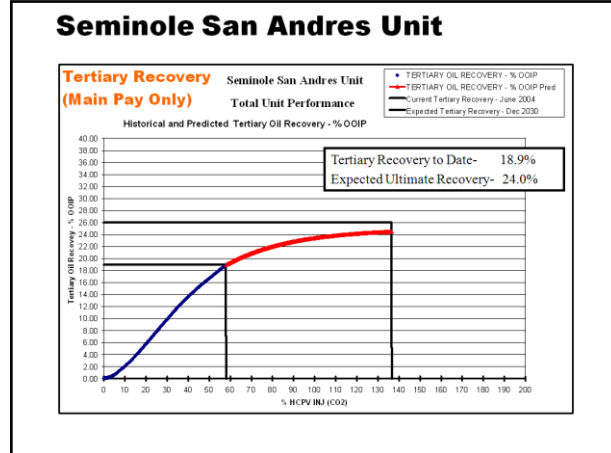
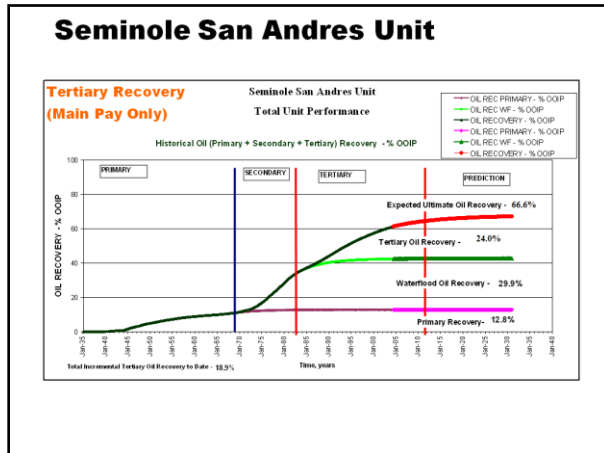
Tertiary CO₂ Injection operations into the Main Pay Zone was initiated in 1983. Under CO₂ Injection the field's Main Pay Section is expected to recover an additional 24% of its Original Oil-in-Place (OOIP).



Seminole Unit
Bibliography References: 58 thru 65

Seminole San Andres Unit – (Main Pay Oil Zone Example)

Primary, Secondary, and CO₂ Tertiary Main Pay Oil Recovery as a percent of Original Oil-in-Place (OOIP) are shown below. Under Primary Operations, the field would have recovered 12.8% of its OOIP before abandoning operations. Water flood operations would have increased oil recovery to 42.7% OOIP (Primary plus Secondary). Tertiary operations with CO₂ in the Main Pay zone would have increased oil production by 24% OOIP. Total Primary+Secondary+Tertiary (MP) = 66.6% OOIP.

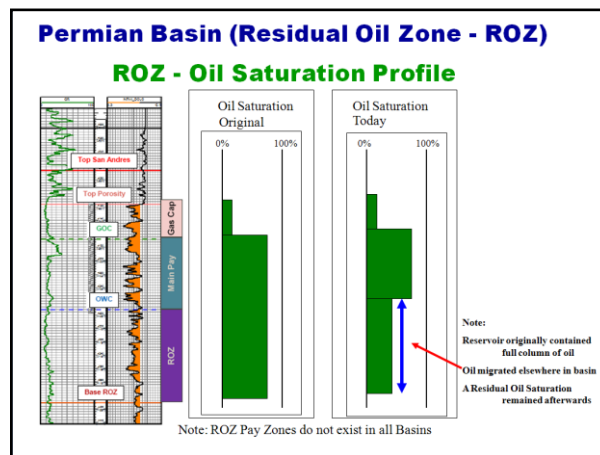
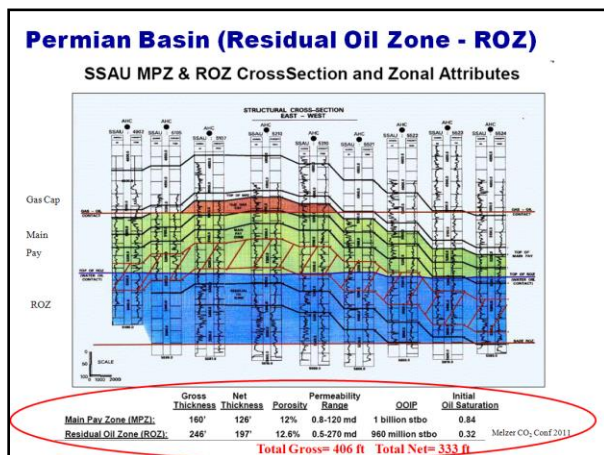


Seminole San Andres Unit – (Main Pay – Amerada Hess WAG Management)

The Main Pay Zone was developed on Inverted a Nine-spot Pattern development. In 1983, the field initiated CO₂ injection into a phased-in pattern development across the field. By 1987, 95% of the CO₂ flood had been completed south to the town of Seminole. Amerada Hess's WAG Management was based on a 2:1 WAG Ratio with 3.0% HCPV CO₂ Half cycles and 6.0% HCPV Water Half Cycle. The field has maintained or increased the water to better control gas breakthrough over time.

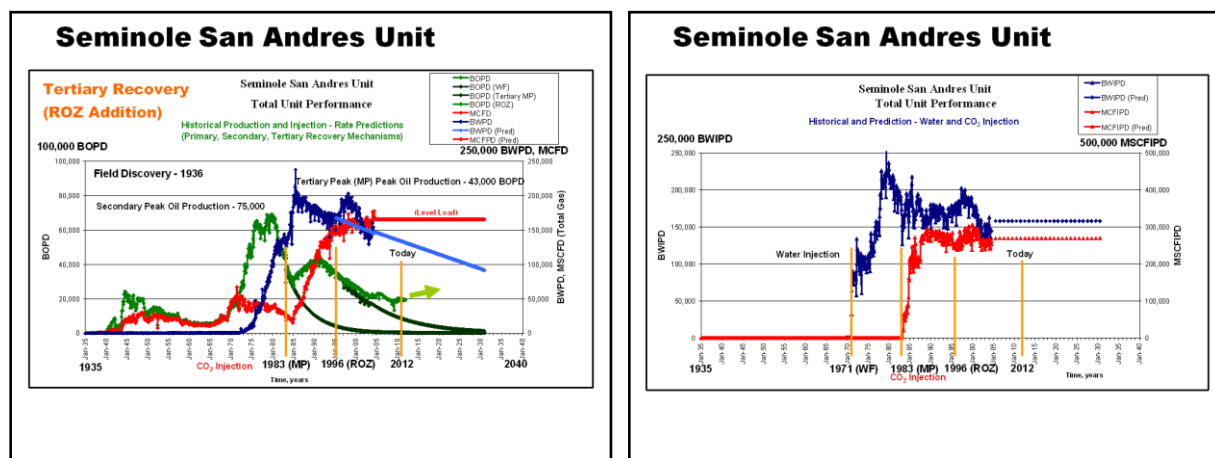
Seminole San Andres Unit – (Residual Oil Zone (ROZ) Example)

A Residual Oil Zone (ROZ) is created when oil within the original oil column migrates away from the field over geologic time creating a ROZ interval. In addition to the Main Pay Zone, the Seminole field contains a very large Residual Oil Zone (ROZ). The size of the ROZ is about the same size at the residual oil remaining in the Main Pay. CO₂ Injection commenced in 1996 into the ROZ. Injection into the ROZ will extend field life beyond the 2050's.



Seminole Unit

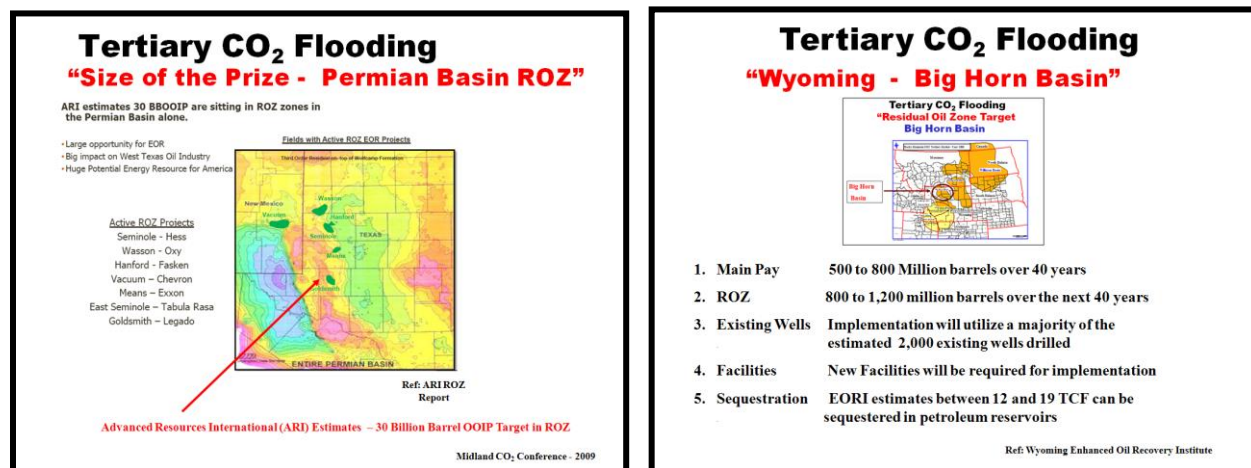
Bibliography References: 58 thru 65



The Residual Oil Zone is responding well to CO₂ Injection. Since the ROZ reserves have never been tied to any Basin Study Estimates, these reserves are “NEW” bookable reserves. Future Performance is based on ROZ reservoir characterization unique to the Seminole field. Tertiary Performance is expected to be similar to that of the Main Pay or better, which depends on the quality of the ROZ pay section.

Residual Oil Zone (ROZ) Enhanced Oil Recovery Potential

Compared to other types of oil recovery mechanisms, CO₂ is the best method designed to recover tertiary oil from Residual Oil (ROZ) Zones. Residual Oil Zones have been identified across the World. The Permian basin is the first region to identify it, characterize it, and now exploit it. Advanced Resources International has estimated the ROZ in the Permian Basin could contain as much as 30 Billion barrels of recoverable tertiary oil from the ROZ. The Wyoming Enhanced Oil Recovery Institute has estimated the state of Wyoming may contain as much as 800 to 1,200 million barrels of ROZ potential in the Big Horn Basin of Wyoming, not counting potential in other basins in the region.



Anthropogenic CO₂ through CO₂ sequestration could expand this target to areas of the World that contain ROZ zones, but lacked the CO₂ to make the projects economically attractive.

CO₂ Flooding in the 2000's (New Millennium)

In the 21st Century, the benefit of controlling the CO₂ WAG process has extended oil recovery to new levels. As previously shown, the Seminole Main Pay CO₂ flood in the Permian Basin is expected to recover 24% of its Original Oil-in-Place with a 140% HCPV injection of CO₂, not counting the additional recovery from the ROZ.

Tertiary CO₂ Flooding

"The New Millennium"

21st Century (2000 and beyond)

"Life beyond 80% HCPV Injected"

The New Millennium

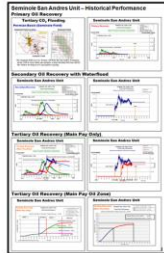


However, not all CO₂ floods are alike; Tertiary Oil Recovery from sandstone reservoirs are different from recovery from carbonate reefs just as un-fractured reservoirs are different from fractured reservoirs.

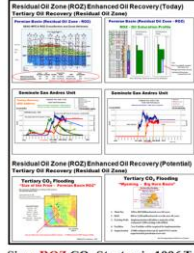
Tertiary CO₂ Flooding

Permian Basin (Seminole Field)

Main Pay Performance



ROZ Performance



ROZ
30
Billion
OOIP
Barrel
Target

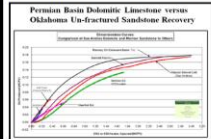
Since CO₂ Startup in 1983 Tertiary Oil Recovery in the Main Pay is expected to recover 24% OOIP

Since ROZ CO₂ Startup in 1996 Tertiary Oil Response had been excellent with expected ROZ Tertiary Oil Recovery comparable or better than Main Pay Tertiary Oil Recovery

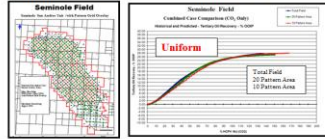
Tertiary Oil Recovery

%OOIP Rec versus %HCPV Inj

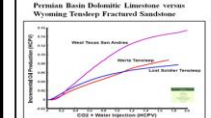
Un-fractured Sandstone versus Dolomite



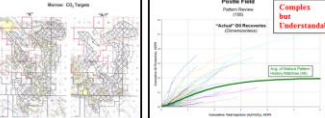
Homogeneous Dolomite - Seminole Unit



Fractured Sandstone versus Dolomite



Non-Uniform Pattern Sandstone - Postle field



Not all Patterns and Reservoirs are alike

What are they doing?

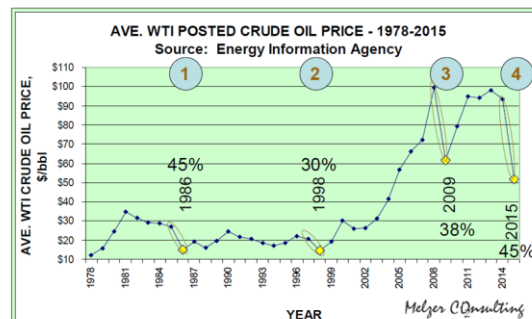
CO₂ Tertiary Flood Management

Pattern Review In Progress: Control Central



- WAG management and surveillance systems in place
 - 24 hour allocation
 - 30 week long pattern reviews
 - Engineering and field personnel participation (and getting it)
1. Evaluating Individual Well Performance
 2. Evaluating Individual Pattern Performance
 3. Making WAG Adjustments based on Pattern Performance

West Texas Intermediate Oil Price vs. Year and Oil Price Crashes Over the Last Four Decades



Ref. 108

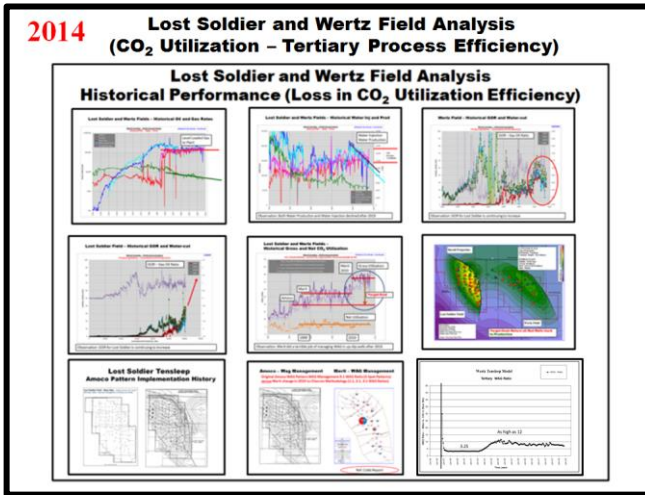
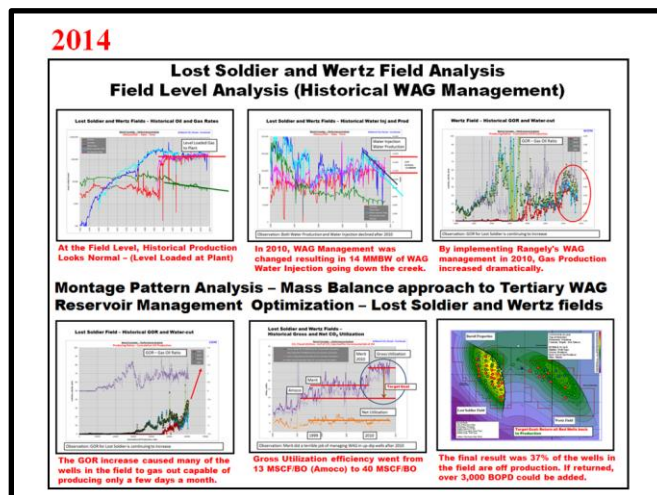
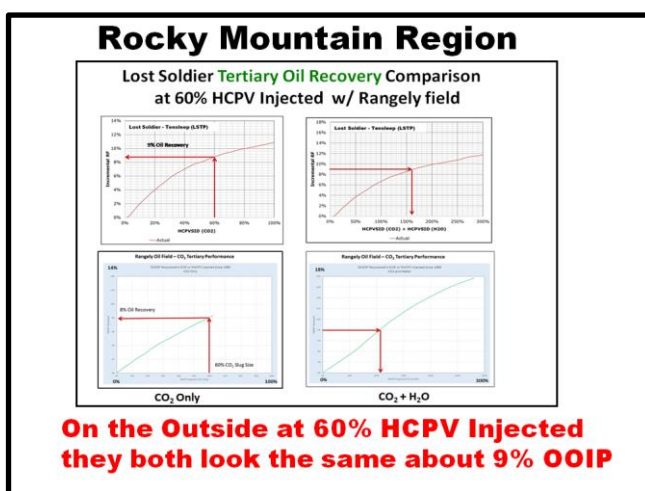
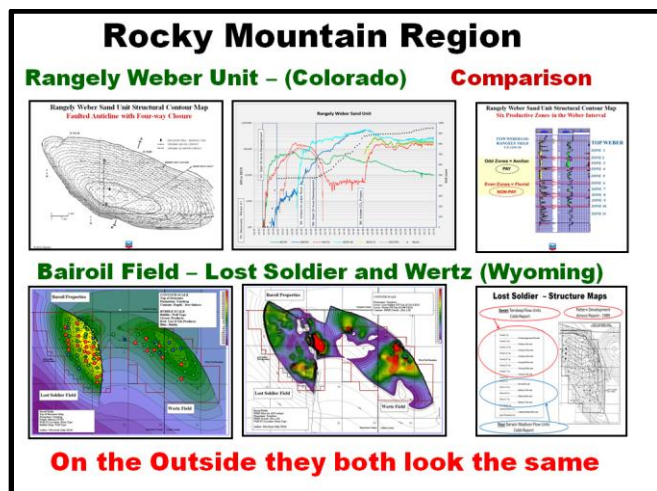
Tertiary Oil Recovery with CO₂ has also weathered **Four** Oil Price Adjustment Periods with the last one in 2015 dropping 45% just like the one back in 1986 that also dropped oil price by 45%. Today, over 90% of the CO₂ Floods that were put on in the 1980's are still producing today. This could only be accomplished through **good Reservoir Management Practices** including the "Pattern Review Process" where WAG adjustments are made.

CO₂ Flooding in the Rocky Mountains (WAG Management Decisions (The Good, the Bad, and the Ugly))

Different Operators in the 1980's developed different WAG philosophies depending on the reservoir pattern configuration, formation dip, reservoir pressure, miscibility pressure, etc. As technology improved, advancements in CO₂ flood design were implemented into reservoir management practices to improve overall performance. However, companies should be aware that **NOT** all reservoirs are alike even though they were formed in the same geologic time period with similar producing characteristics.

The example shown below illustrates the fact that not all reservoirs are alike. The Rangely Weber Unit in Wyoming produces from the Weber Sand which is similar in geologic age to Bairoil's Tensleep Reservoir producing section. In addition, CO₂ Tertiary WAG performance at 60% CO₂ HCPV Injected recovers about 9% OOIP in both fields.

NOT ALL FORMATIONS ARE THE SAME



In 2010, Merit Company, who operated the field, modified Amoco's five-spot pattern 9:1 WAG scheme to Rangely's 1:1, 2:1, and 3:1 WAG scheme by dividing the unit up into thirds. From 2010 to 2014, 14 million barrels of water went down the creek that was supposed to be used for WAG Management. The overall effect gassed out 37% of the wells in the Lost Soldier field that deteriorated Amoco's Gross CO₂ Utilization WAG efficiency rating of 13 MSCF/BO to over 40 MSCF/BO under Merit's operatorship.

Fortunately **BAD WAG** Practices can be fixed.....

Life beyond 80% HCPV- (Tertiary Oil Recovery, CO₂ Gross and Net Utilization)

Since 1972, over 130+ Commercial CO₂ floods have been operated in the United States with the majority 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 CO₂ floods today?” And “What would Oil Recovery, Gross Utilization and Net Utilization look like under Extended CO₂ Slug volumes?” The answer to those questions depends on Reservoir Type. Data from these CO₂ projects from various SPE and DOE reports are listed below by formation type:

Table 2. - San Andres and Grayburg Formation – Dolomite

State	Formation	Field	Lease	Current Economic			Life beyond 80% HCPV Inj			Bibliography References
				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)	
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 QOC 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)

State	Formation	Field	Lease	Current Economic			Life beyond 80% HCPV Inj			Bibliography References
				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)	
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

State	Formation	Field	Lease	Current Economic			Life beyond 80% HCPV Inj			Bibliography References
				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)	
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			Bibliography References
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)	
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 (Fluvial Deltaic, Point Bar, Turbidite)

				Current Economic			Life beyond 80% HCPV Inj			Bibliography References
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)	
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			Bibliography References
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)	
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			Bibliography References
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)	
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 forty-five years of successful enhanced oil recovery (EOR) projects in the Permian Basin (Texas), Mississippi, Wyoming, Colorado, California, Oklahoma, and several countries worldwide, carbon dioxide CO₂ flooding is a proven method for extending field life. CO₂ 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, CO₂ is not miscible at first contact with reservoir oils, but miscibility can be developed in reservoirs above or near the Minimum Miscibility Pressure (MMP). CO₂ can attain miscibility through a multiple-contact process that vaporizes or extracts both intermediate and higher molecular weight hydrocarbons from the reservoir oil. The CO₂ 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 CO₂ flooding involved the displacement efficiency of the process, how CO₂ 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 CO₂ Tertiary Recovery. A reservoir must contain certain characteristics for a CO₂ 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 CO₂ and oil develop total miscibility. This is not necessary correct. Most CO₂ floods operate at reservoir pressures that are above their minimum miscibility pressure. But today, it is not uncommon to find CO₂ projects that operate below or near the minimum miscibility pressure. The CO₂ still produces tertiary oil. The process is not as efficient as that operated above the minimum miscibility pressure. Most historical CO₂ 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 a 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

CO₂ source and low oil price environment, a good number of wells increased oil rate from 30 BOPD to over 300 BOPD after CO₂ was injected. CO₂ has the ability to affect the full C₂ through C₃₀₊ compositional range. Whereas, Nitrogen, and in some cases flue gas injection, will only extract the lighter components (C₂ through C₆). 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 CO₂ injection stream to lower the minimum miscibility pressure and improve overall oil recovery.

References

Conventional WAG CO₂ Flood History

1. Turek, E.A., Christopher, C.A., Stein, M.H., Merchant, D.H., "History of WAG Development" by Turek, Prepared for BP under Amoco's Learning Program, Internal Report, October, 2000.
2. Merchant, D.H., "GWR and Slug Size Optimization of the WAG Process", Prepared for Amoco Production Company, Permian Basin Business Unit, Internal Report, File: JWA-539.41-111, Model Study 1986-1987, Report Published: January 1988.
3. Merchant, D.H., "Injection Well Profiling of the CO₂ Recovery Process", Prepared for Amoco Production Company, Permian Basin Business Unit, Internal Report, File: DDF-539.41-1586, Model Study 1987-1988, Report Published: August 1988.
4. Merchant, D.H., "EOR/ CO₂ Storage Optimization and Economics 2004 CCP Program ", Prepared for BP Alternative Energy under the Carbon and Capture Program CCP, An Integrated, Collaborative Technology Development Project for Next Generation CO₂ Separation, Capture and Geologic Sequestration, Subcontract C010: EOR/CO₂ Storage Optimization and Economics – 2004 Program, Date Published: December 2004.
5. Merchant, D.H., "Enhanced Oil Recovery Methods – Conventional CO₂ WAG Injection", Prepared for BP Alternative Energy under the Carbon and Capture Program CCPI, An Integrated, Collaborative Technology Development Project for Next Generation CO₂ Separation, Capture and Geologic Sequestration, Subcontract C010: EOR/CO₂ Storage Optimization and Economics – 2004 Program, Date Published: October 2005.
6. Merchant, D.H., "Comparisons of Conventional CO₂ WAG Injection Techniques used in the Permian Basin", presented at the 15th Annual CO₂ Flooding Conference, Midland, Texas, and December 10-11, 2009.
7. Tanner, C.S., Baxley, P.T., CHI, J.G., and Miller W.C., "Production Performance of the Wasson Denver Unit CO₂ Flood," SPE 24156, SPE/DOE Eighth Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 1992.
8. Kittridge, M.G., "Quantitative CO₂ Monitoring, Denver Unit, Wasson (San Andres field), SPE 24644, presented at the 67th Annual Technical Conference and Exhibition of SPE held in Washington DC, October, 1992.
9. Hsu, C-F, Morell, J.I., Falls, A.H., "Field-Scale CO₂ Flood Simulations and Their Impact on the Performance of the Wasson Denver Unit", SPE 29116, presented at 13th SPE Symposium on Reservoir Simulation held in San Antonio, Texas, 12-15 February 1995.
10. Coalmer, M.S., Hsu, C.F., Cooper, J.C., Ward, J.B., Voto, J.G., Way, K.F., and Valdez, R., "Reservoir Characterization and Development Plan of the Wasson San Andres Denver Unit Gas Cap", SPE 56549-MS, presented at the Annual Technical Conference and Exhibition of SPE held in Houston, Texas, October 3-6, 1999.
11. Koperna, G.J., Melzer, L.S., Kuuskraa, V.A., "Recovery of Oil Resources From the Residual and Transitional Oil Zones of the Permian Basin", SPE 102972-MS, presented at the Annual Technical Conference and Exhibition of SPE held in San Antonio, Texas, September 24-27, 2006.
12. Bullock, G.W., Wood, T.B., Konecki, M.L., "A Brief History of the Wasson EOR Project", Wasson ODC, SPE 17754-PA, SPE Production Engineering Journal, Volume 5, Number 3, Pages 338-344, August, 1990.
13. Todd, M.R., Cobb, W.M., McCarter, E.D., "CO₂ Flood Performance Evaluation for the Cornell Unit, Wasson San Andres Field", SPE 10292-PA, Journal of Petroleum Technology, Volume 34, Number 10, Pages 2271-2282, October 1982.
14. Hsu, C-F, Fitzgerald, M.A., Musallam, S.C., McCray, T.L., Purvis, W.D., "Design and Implementation of a Grass-Roots CO₂ Project for the Bennett Ranch Unit", SPE 35188, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 27-29, 1996.
15. Altura Company, "Wasson Field, Bennett Ranch Unit, Wasson ODC Unit, and Denver Unit CO₂ Performance Update, Yoakum and Gaines County, Texas", presented at the Annual CO₂ Flooding Conference, Midland, Texas, December 7-8, 1999.
16. Johnston, J.W., "A Review of the Willard (San Andres) Unit CO₂ Injection Project", SPE 6388-MS, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 10-11, 1977.
17. Wang, F.P., Lucia, F.J., Kerans, C., "Integrated Reservoir Characterization Study of a Carbonate Ramp Reservoir: Seminole San Andres Unit, Gaines County, Texas", SPE 36515-PA, SPE Reservoir Evaluation and Engineering Journal, Volume 1, Number 2, Pages 105-113, April 1998.

18. Melzer, L.S., Koperna, G.J., Kuuskraa, V.A., "The Origin and Resource Potential of Residual Oil Zones", SPE 102964-MS, presented at the Annual Technical Conference and Exhibition of SPE held in San Antonio, Texas, September 24-27, 2006.
19. Rowe, H.G., York, S.D., and Ader, J.C., "Slaughter Estate Unit Tertiary Pilot Performance", SPE 9796, presented at the 1981 SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, April 5-8, 1981.
20. Ader, J.C. and Stein, M.H., "Slaughter Estate Unit Tertiary Miscible Gas Pilot Reservoir Description," SPE 10727, Oil and Gas Journal, May, 1984.
21. Stein, M.H., Frey, D.D., Walker, R.D., and Pariani G.J., "Slaughter Estate Unit CO₂ Flood: Comparison between Pilot and Field-Scale Performance", SPE 13975, JPT, September, 1992.
22. Pariani, G. J., McCofloch, K. A., Warden, SJ., and Edens, D.R., "An Approach To Optimize Economics in a West Texas CO₂ Flood," JPT, Sept., 1992.
23. Merchant D.H. and Thakur, S.C., "Reservoir Management in Tertiary CO₂ Floods", SPE 26624, presented at the 68th Annual Technical Conference and Exhibition, Houston, Texas, October 1994.
24. Drennon, M.D., Kelm, C.H., and Whittington, H.M., "A Method for Appraising the Feasibility of Field-Scale CO₂ Miscible Flooding," SPE 9323, 1980 SPE Annual Technical Conference and Exhibition, Dallas, Sept 21-24, 1980.
25. Honnert, M., Creel, P., Tate, R., and Everett, D., "Five Years of Ongoing Conformance Work in the Central Mallet Unit CO₂ Flood in West Texas Yields Improved Economics for Operator", SPE 101701-MS, presented at First International Oil Conference and Exhibition in Mexico, August 31st to September 2nd, 2006.
26. Guillot, S.N., "Horizontal Well Applications in a Miscible CO₂ Flood, Sundown Slaughter Estate Unit, Hockley County, Texas", SPE 30742, SPE Annual Technical Conference and Exhibition, Dallas, October 22-25, 1995.
27. Folger, L.K., "Improved CO₂ Flood Predictions Using 3D Geologic Description and Simulation on the Sundown Slaughter Unit", SPE 35410, presented at SPE/DOE Tenth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 21-24, 1996.
28. Folger, L.K., Guillot, S.N., "A Case Study of the Development of the Sundown Slaughter Unit CO₂ Flood Hockley County, Texas", SPE 35189, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 27-29, 1996.
29. Kuo, M.C.T., Dulaney, J.P., Deer, M.W., Evans, B.S., Granquist, M.R., "Optimization of Waterflood Performance and CO₂ Flood Design Using a Modelling Approach, Mallet Unit, Slaughter Field", SPE 20377, presented at the 65th Annual Technical Conference and Exhibition held in New Orleans, LA, September 23-26, 1990.
30. Henry, R.L., Feather, G.L., Smith, L.R., Fussell, D.D., "Utilization of Composition Observation Wells in a West Texas CO₂ Pilot Flood", Levelland Unit, SPE 9786-MS, presented at SPE/DOE Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 5-8, 1981.
31. Yellig, W., "Carbon Dioxide Displacement of a West Texas Reservoir Oil", Levelland, SPE 9785-PA, SPE Oil and Gas Journal, Volume 22, Number 6, Pages 805-815, December, 1982.
32. Macon, R.B., Design and Operation of the Levelland Unit CO₂ Injection Facility", SPE 8410-MS, presented at the Annual Technical Conference and Exhibition held in Las Vegas, Nevada, September 23-26, 1979.
33. Magruder, J.B., Stiles, L.H. and Yelverton, T.D., "A Review of the Means San Andres Full-Scale CO₂ Tertiary Project", SPE/DOE 17349, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, April 17-20, 1988.
34. Hambly, E., "Means San Andres Unit – A History of CO₂ Flood Performance and Management", presented at the Annual CO₂ Flooding Conference, Midland, Texas, December 7-8, 1999.
35. Jasek, D.E., Frank, J.R., Smith, D.J., "Goldsmith San Andres Unit CO₂ Pilot – Design, Implementation, and Early Performance", SPE 48945-MS, presented at the Annual Technical Conference and Exhibition held in New Orleans, LA, September 27-30, 1998.
36. Merchant, D.H., "Goldsmith Unit – Tertiary Performance Evaluation – CO₂ Prediction", developed for Shell CO₂ Company and Chevron USA, Internal Report, January, 2000.
37. Merritt, M.B. and Groce, J.F., "A Case History of the Hanford San Andres Miscible CO₂ Project", SPE/DOE 20229, presented at the SPE/DOE Seventh Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 22-25, 1990.
38. Brownlee, M.H. and Sugg, L.A., "East Vacuum Grayburg-San Andres Unit CO₂ Injection Project Development and Results to Date", SPE 16721, presented at the 62nd Annual Technical Conference and Exhibition, Dallas, Texas, Sept 27-30, 1987.
39. Martin, F.D. and J.E. Stevens, Harpole, K.J., "CO₂-Foam Field Test at East Vacuum Grayburg/San Andres Unit", SPE 27786, presented at the SPE/DOE Tenth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 17-20, 1995.
40. Boomer, R.J., "Central Vacuum Unit CO₂ Performance Overview (SE New Mexico)", presented at the Annual CO₂ Flooding Conference, Midland, Texas, December 7-8, 2001.

41. Pittaway, K.R., Albright, J.C. and Hoover, J.W., "The Maljamar Carbon Dioxide Pilot: Review and Results", SPE/DOE 14940, presented at the SPE/DOE Fifth Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 20-23, 1986.
42. Moore, J.S. and Clark, G.C., "History Match of the Maljamar CO₂ Pilot Performance", SPE/DOE 17323, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, April 17-20, 1988.
43. Roper, M.K., Cheng, C.T., Varnon, J.E., Pope, G.A. Sepehmooi, K., "Interpretation of a CO₂ WAG Injectivity Test in the San Andres Formation Using a Compositional Simulator", Mabee Field, SPE 24163-MS, presented at the SPE/DOE Seventh Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 22-24, 1992.
44. Jaramillo, A.R., "Utilization of a Black-Oil Simulator as a Monitor of Waterlood Operations in a San Andres Reservoir", SPE 19046-MS, GMK Unit, Unsolicited, This document was submitted for consideration for publication but included in SPE library, 1989.
45. Taylor, A.R. Hinterlong, G.H., Kumar, K.H., "West Welch CO₂ Flood Simulation with an Equation of State and Mixed Wettability", SPE 39808, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 23-26, 1998.
46. Keeling, R.J., "CO₂ Miscible Flooding Evaluation of the South Welch Unit, Welch San Andres Field", SPE/DOE 12664, presented at the SPE/DOE Fouth Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 15-18, 1984.
47. Hallenbeck, L.D., Harpole, K.J., Sistrunk, G.T., and Wier, D.R., "Innovative Approach to CO₂ Project Development Holds Promise for Improving CO₂ Flood Economics in Smaller Fields Nearing Abandonment ", South Cowden Field Example, SPE 28334, presented at the 69th Annual Technical Conference and Exhibition held in New Orleans, LA, September 25-28, 1994.
48. Wegener, D.C., Harpole, K.J., "Determination of Relative Permeability and Trapped Gas Saturation for Predictions of WAG Performance in the South Cowden CO₂ Flood", SPE/DOE 35429, presented at the SPE/DOE Tenth Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 21-24, 1996.
49. Oxy Permian, "Anton Irish Clearfork CO₂ Flood Case History" presented at the Annual CO₂ Flooding Conference, Midland, Texas, December 7-8, 1999.
50. Burbank, D.E., "Early CO₂ Flood Experience at the South Wasson Clearfork Unit", SPE/DOE 24160, presented at the SPE/DOE Eighth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 22-24, 1992.
51. Poole, E.S. "Evaluation and Implementation of CO₂ Injection at the Dollarhide Devonian Unit", SPE 1722, presented at the SPE Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 1988.
52. Poole, E.S., "Evaluation and Implementation of CO₂ Injection at the Dollarhide Devonian Unit", SPE 17277, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 10-11, 1988.
53. Lin, E.C., Poole, E.S., "Numerical Evaluation of Single-Slug, WAG, and Hybrid CO₂ Injection Processes, Dollarhide Devonian Unit, Andrews County Texas", SPE 20098, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 1990.
54. Bellavance, J.F.R., "Dollarhide Devonian CO₂ Flood: Project Performance Review 10 years later", SPE 35190, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 27-29, 1996.
55. Kovarik, J.J., Prasad, R.K., and Waddell, Wade, and Watts, "North Dollarhide (Devonian) Unit: Reservoir Characterization and CO₂ Feasibility Study", SPE 27678, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 1994.
56. Pontius, S.B. and Tham, M.J., "North Cross (Devonian) Unit CO₂ Flood – Review of Flood Performance and Numerical Simulation Model", Journal of Petroleum Technology (December 1988), pp 1706-1714.
57. Mizenko, G.J., "North Cross (Devonian) Unit CO₂ Flood: Status Report", SPE/DOE 24210, presented at the SPE/DOE Eighth Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 22-24, 1992.
58. Crameik, T.D., Plassey, J.A., "Carbon Dioxide Injection Project Sacroc Unit, Scurry County, Texas", SPE 72-D001, presented at the Annual Meeting Papers, Division of Production, Houston, Texas, March 6-8, 1972.
59. Graue, D.J., Blevins, T.R., "Sacroc Tertiary CO₂ Pilot Project", SPE 7090-MS, presented at the SPE Symposium on Improved Methods of Recovery, Tulsa, Oklahoma, April 16-17, 1978.
60. Kane, A.V., "Performance Review of a Large-Scale CO₂-WAG Enhanced Recovery Project, Sacroc Kelly-Snyder Field," SPE 7091-PA, Journal of Petroleum Technology, Volume 31, Number 2, Pages 217-231, February 1979.
61. Gill, T.E., "Ten Years of Handling CO₂ for Sacroc Unit", SPE 11162-MS, presented at the Annual Technical Conference and Exhibition of Society of Petroleum Engineers, New Orleans, LA, September 26-29, 1982.
62. Langston, M.V., Hoadley, S.F., Young, D.N., "Definitive CO₂ Flooding Response in the Sacroc Unit", SPE 17321-MS, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, April 17-20, 1988.
63. Hawkins, J.T., Benvegnu, A.J., Wingate, T.P., McKameie, J.D., Pickard, C.D., Altum, J.T., "Sacroc Unit CO₂ Flood: Multidisciplinary Team Improves Reservoir Management and Decreases Operating Costs", SPE Reservoir Engineering, August 1996.
64. Bayat, M.G., Pickard, C.D., Benvegnu, A.J., Wingate, T.P., Larkin, R., "Linking Reservoir Characteristics and Recovery Processes at Sacroc", Second Annual Subsurface Fluid Control Symposium, Houston, Texas, September, 1996.

65. Gonzalez, R., Schepers, K., Reeves, S., Eslinger, E., Back, T., "Integrated Clustering/Geostatistical/Evolutionary Strategies Approach for 3D Reservoir Characterization and Assisted History Matching in a Complex Carbonate Reservoir, Sacroc Unit, Permian Basin", SPE 113978-MS, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, April 20-23, 2008.
66. Genetti, D.B., Whitaker, C.A., Smith, D.P., Price, L.M., "Applying Improved Recovery Processes and Effective Reservoir Management to Maximize Oil Recovery at Salt Creek", SPE 81458-MS, presented at the Middle East Oil Show, Bahrain, June 9-12, 2003.
67. Bishop, D.L., Williams, M.E., Gardner, S.E., Smith, D.P., Cochrane, T.C., "Vertical Conformance in a Mature Carbonate CO₂ Flood: Salt Creek Field Unit, Texas", SPE 88720-MS, presented at the Abu Dhabi International Conference and Exhibition, Abu Dhabi, United Arab Emirates, October 10-13, 2004.
68. Brinkman, F.P., Kane, T.V., McCullough, R.R., Miertschin, J.W., "Use of Full-Field Simulation to Design a Miscible CO₂ Flood", Sharon Ridge Field, SPE 56882-PA, SPE Reservoir Evaluation and Engineering Journal, Volume 2, Number 3, pages 230-237, June, 1999.
69. Brown, G., Carvalho, B., Wray, A., Sensa, Smith, D., Tooms, M., Pennell, S., "Monitoring Alternating CO₂ and Water Injection and its Effect on Production in a Carbonate Reservoir using Permanent Fiber-Optic Distributed Temperature Systems", Cogdell Field, SPE 90248-MS, presented at the Annual Technical Conference and Exhibition of Society of Petroleum Engineers, Houston, Texas, September 26-29, 2004.
70. Smith, D. and Kelly, T., "Katz (Strawn) Field CO₂ Project – Permian Basin, Texas", presented at the 15th Annual CO₂ Flooding Conference, Midland, Texas, December 10-11, 2009.
71. Roy, M.B., Tucker, C.W., Lakey, C.J., Cloud, W.B., "Waterflood Redevelopment Prior to Future Tertiary Attempts – A Case History", SPE 8460 MS, Postle, presented at the SPE Oklahoma City Regional Meeting, Oklahoma City, Oklahoma, February 21-22, 1977.
72. Wehner, S.C., "A CO₂ EOR Update from "No Man's Land", Challenges and Successes – Postle Field, Oklahoma", presented at the 15th Annual CO₂ Flooding Conference, Midland, Texas, December, 10-11, 2009.
73. Kirpatrick, R.K., Flanders, W.A., and Depauw, R.M., "Performance of the Twofreds CO₂ Injection Project", SPE 14439, presented at the SPE/DOE Fourth Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 15-18, 1984.
74. Flanders, W.A., and Depauw, R.M., "Update Case History: Performance of the Twofreds Tertiary CO₂ Project", SPE 26614-MS, presented at the Annual Technical Conference and Exhibition of Society of Petroleum Engineers, Houston, Texas, October 3-6, 1993.
75. Flanders, W.A., and McGinnis, R.A., "CO₂ EOR Economics for Small-to-Medium-Size Fields", SPE 26391-MS, presented at the Annual Technical Conference and Exhibition of Society of Petroleum Engineers, Houston, Texas, October 3-6, 1993.
76. Pittaway, K.R. and Runyan, E.E., "The Ford Geraldine Unit CO₂ Flood: Operating History", SPE 17278, presented at the SPE Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 10-11, 1988.
77. Phillips, J.L., McPherson, J.L., and Leibrecht, R.J., "CO₂ Flood: Design and Initial Operations, Ford Jeraldine (Delaware Sand) Unit", SPE 12197, presented at the 58th Annual Technical Conference and Exhibition held in San Francisco, CA, October 5-8, 1983.
78. Fox, M.J., Simlote, V.N., Stark, K.L., and Brinlee, L.D., "Review of CO₂ Flood, Springer "A" Sand, NE Purdy Unit", SPE/DOE 14938, presented at the SPE/DOE Fifth Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 20-23, 1986.
79. Flanders, W.A., Stanberry, W.A., and Martinez, M., "Review of CO₂ Performance of the Hansford Marmaton Unit", SPE/DOE 12327, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, April 17-20, 1988.
80. Ring, J.N., "An Overview of the North Ward Estes CO₂ Flood", SPE 30729, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, October 22-25, 1995.
81. Oxy Elk Hills, "Enhanced Recovery from Mature Fields - An Operators Perspective", presented at RPSEA Problem Identification Forum, University of California – School of Engineering, November 29, 2006.
82. Kleinsteinber, S.W., "The Wertz Tensleep CO₂ Flood: A Review of the Engineering Design and Initial Performance", SPE 18067, presented at the 63rd Annual Technical Conference and Exhibition of Society of Petroleum Engineers, Houston, Texas, October 2-5, 1988.
83. Brokmeyer, R.J. and Borling, D.C., "Lost Soldier Tensleep CO₂ Tertiary Project – Performance Case History – Bairoil, Wyoming", SPE 35191, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 27-29, 1996.
84. Merit Energy Company, "Baroil Operations Center – CO₂ Tertiary Recovery Review Lost Soldier and Wertz Fields, Sweetwater and Carbon County, Wyoming", Fourth Annual Wyoming Natural Gas Fair, September 28, 2000.
85. Eves, K.E. and Nevarez, J.J., "Update of Lost Soldier/Wertz Floods – Living in a Constrained CO₂ Environment", presented at the 15th Annual CO₂ Flooding Conference, Midland, Texas, December 10-11, 2009.

86. Kulkarni, M. M., Chen, Hung-Lung, Brummert, A.C., "CO₂ IOR Evaluation for the U.S. Rocky Mountain Assets", SPE 113297-MS, presented at the SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 20-23, 2008.
87. Larson, W.K., "Rangeley Weber Sand CO₂ Project: A Case History", presented at the Denver SPE MiniSymposium, November 19, 1987.
88. Wackowski, R.K., Stevens, C.E., Masoner, L.O., Attanucci, V., Larson, J.L., Aslesen, K.S., "Applying a Rigorous Decision Analysis Methodology to Optimization of a Tertiary Recovery Project: Rangely Weber Sand Unit, Colorado", SPE Oil and Gas Economics, Finance, and Management Conference held in London, England, 28-29, April 1992.
89. Wakowski, R.K. and Masoner, L.O., "Rangely Weber Sand Unit CO₂ Project Update: Operating History", SPE/DOE 27755, presented at the SPE/DOE Ninth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 17-20, 1994.
90. Fulbright, G.D, Hild, G.P., Horf, T.A., Myers, F.S., O'Toole, F.S., Wakowski, R.K., "Evolution of Conformance Improvement Efforts in a Major CO₂ WAG Injection Project, Rangely Field, Colorado", SPE/DOE 35361, presented at SPE/DOE Tenth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 21-24, 1996.
91. Masoner, L.O., Abidi, H.R., Hild, G.P., "Diagnosing CO₂ Flood Performance Using Actual Performance Data", Rangely Field – Colorado, SPE/DOE 35363, presented at SPE/DOE Tenth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 21-24, 1996.
92. Wackowski, R.K., "Rangely Weber Sand Unit CO₂ Project Update", Powerpnt talk presented at the 5th Annual CO₂ Flooding Conference, Midland, Texas, December 10-11, 1999.
93. Schechter, D.S., McDonald, P., Sheffield, T., Baker, R. "Integration of Laboratory and Field Data for Development of a CO₂ Pilot in the Naturally Fractured Spraberry Trend Area, Permian Basin, Texas", SPE 36657, presented at the Annual Technical Conference and Exhibition held in Denver, CO., October 6-9, 1996.
94. Schechter, D.S., McDonald, P., Sheffield, T., Baker, R. "Reservoir Characterization and CO₂ Pilot Design in the Naturally Fractured Spraberry Trend Area, Permian Basin, Texas", SPE 35469, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 27-29, 1996.
95. Spivak, A., Garrison, W.H., Nguyen, J.P., "Review of an Immiscible CO₂ Project, Tar Zone, Fault Block V, Wilmington Field, California", SPE 17407-PA, SPE Reservoir Engineering Journal, Volume 5, Number 2, Pages 155-162, May, 1990.
96. Saner, W.B., Patton, J.T., "CO₂ Recovery of Heavy Oil: Field Test", SPE 12082, presented at the Annual Technical Conference and Exhibition held in San Francisco, California, October 5-8, 1983.
97. Sankur, V., Creek, J.L., DiJutio, S.S, Emanuel, A.S., "A Laboratory Study of Wilmington Tar Zone CO₂ Injection Project", SPE 12751, presented at the California Regional Meeting held at Long Beach, California, Apr 17-23, 1984.
98. Jeschke, P.A., Schoeling, L., Hemmings, J., "CO₂ Flood Potential of California Oil Reservoirs and Possible CO₂ Sources", SPE 63305, presented at the SPE/AAPG Western Regional Meeting held in Long Beach, California, June 19-23, 2000.
99. Reid, T.B., Robinson, H.J., "Lick Creek Meakin Sand Unit Immiscible CO₂/Waterflood Project", SPE 9795, presented at SPE/DOE Tenth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 6-7, 1981.
100. Moffitt P.D., Zornes, D.R., "Lick Creek Meakin Sand Unit Immiscible CO₂/Waterflood Project", presented at the 67th Annual Technical Conference and Exhibition held in Washington DC, October 4-7, 1992.
101. Brock, W.R. and Bryan, L.A.: "Summary Results of CO₂ EOR Field Tests, 1972-1987," paper SPE 18977 presented at the 1989 SPE Joint Rocky Mountain Regional/Low Permeability Reservoir Symposium and Exehibition, Denver, 6-8 March, 1989
102. Caudle, B.H. and Dyes, A.B.: "Improving Miscible Displacement by Gas-Water Injection" Trans., AIME (1958) 213, 281.
103. Hadlow, R.E.: "Update of Industry Experience with CO₂ Injection," paper SPE 24928 presented at the 1992 SPE Annual Technical Conference and Exhibition, Washington, DC, 4-7 October.
104. Grigg, R.B. and Schechter, D.S.: "State of the Industry in CO₂ Floods," paper SPE 38849 presented at the 1997 SPE Annual Technical Conference and Exhibition, San Antonio, Texas 5-8 October, 1997
105. John D. Rogers,*SPE, and Reid B. Grigg, SPE, New Mexico Petroleum Recovery Research Center.: "A Litature Analysis of the WAG Injectivity Abnormalities in the CO₂ Process" SPE Report (SPE 73830) was revised for publication, first presented at 2000 SPE/DOE IOR Symposium, Tulsa Apr 3-5 2000
106. Pennzoil's Sacroc Development Team (1994-1998): Dr. Ghasem Bayat, Tony Benvegna, Claud Pickard, Jack Horkowitz, Tom Wingate, Don Hartman; Team was Responsible for Sacroc's Centerline Project plus two other pilot programs that was responsible for 1/3 of Sacroc's total 9,600 BOPD Production through this time period.
107. Amoco's Permian Basin Original Model Development Group: Jack Aulick(Manager), Reservoir Modellers: Kevin McCollough, Steve Pennell, Burt Nelson, Gary Pariani, Dennis Edens, John Kimberling, and David Merchant, Operations: Perry Jarrell; Team was responsible for developing Amoco's Tapered WAG Operating scheme.
108. Steve Melzer, Midland 2016 CO₂ Conference, "Plot of Historical Oil Price Crash Periods from the 1970's through 2016", Date: December 2016.

Acknowledgements

I would like to express my gratitude to the members of the Carbon Management Technology Conference (CMTC) for allowing me the opportunity to be part of this CO₂ Conference. I would especially like to thank George Koperna of Advanced Resources International and Jose Figueroa for their support in making this effort possible.

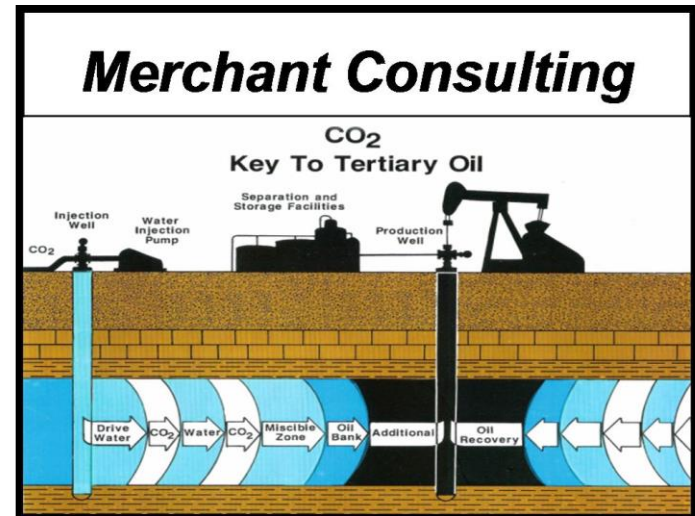
David H. Merchant
Merchant Consulting
Magnolia, Texas

CMTC-502866-MS Enhanced Oil Recovery The History of CO₂ Conventional WAG Injection Techniques developed from Lab in the 1950's to 2017

David H. Merchant



CO₂ Storage Solutions



Merchant Consulting

WEB Site: www.CO2StorageSolutions.com

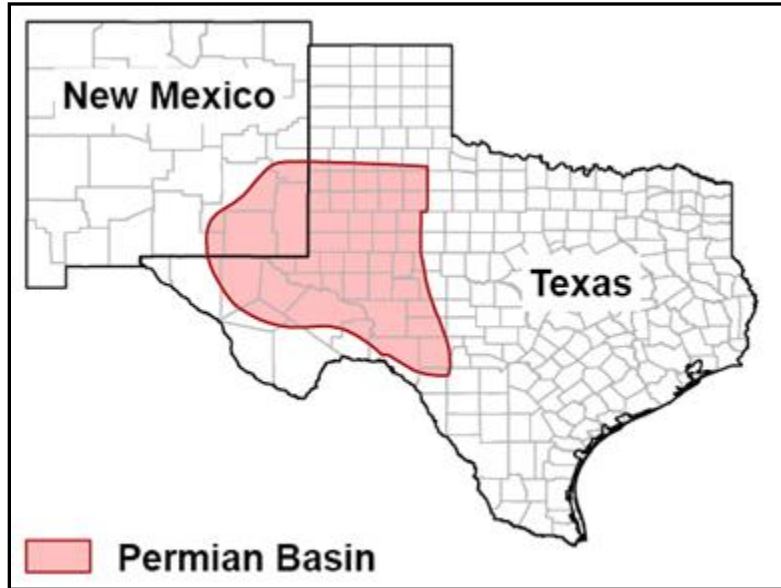
Email: merchantconsulting@comcast.net

Presented to Houston CMTC Conference

**July 18, 2017
Houston, Texas**

Permian Basin

Welcome to the Permian Basin?

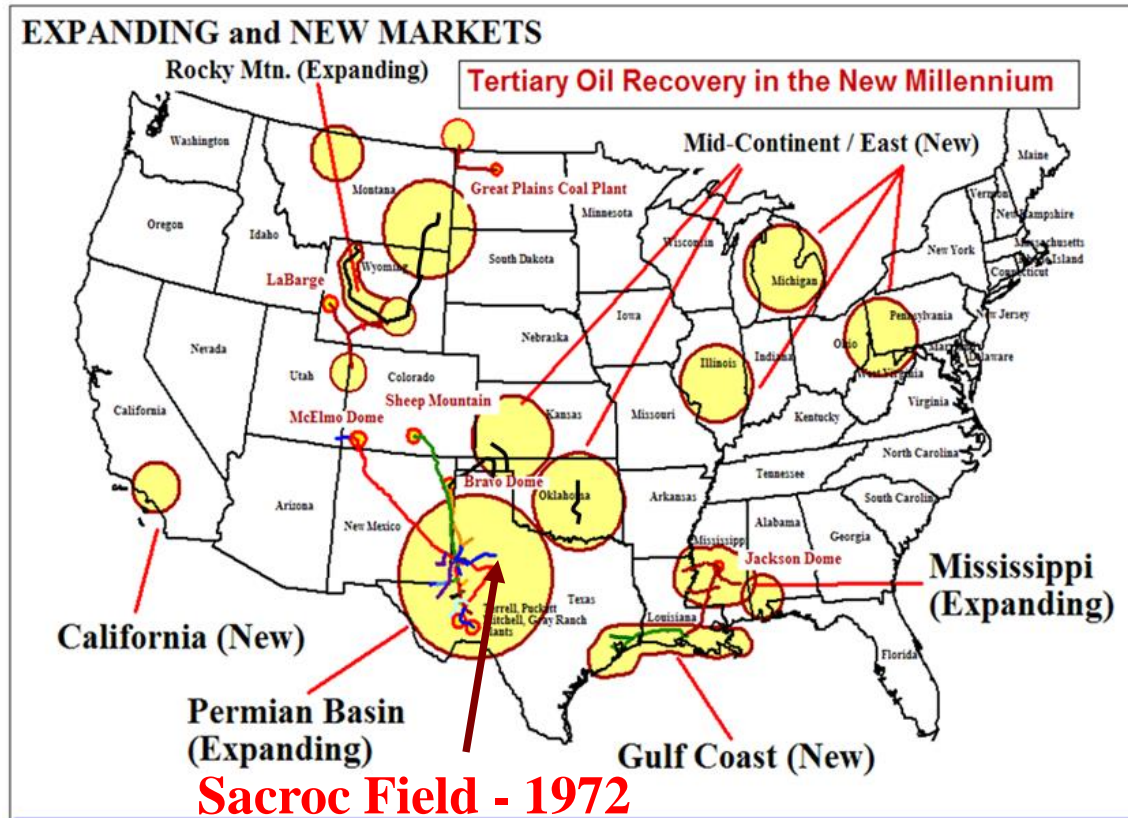


300 miles (480 km) North South

250 miles (400 km) East West

Tertiary CO₂ Flooding

“CO₂ Flood History since 1972”



Since 1972 over 130+ CO₂ Tertiary Projects have been implemented in the United States.

Today, CO₂ projects in the United States produce over 300,000 BOPD with CO₂ transported over 4,500 miles of CO₂ pipeline.

CMTC 2015 Carbon Management Conference - THANKS

CMTC-440075-MS "Life beyond 80 – A Look at Conventional WAG Recovery beyond 80% HCPV Injection in CO₂ Tertiary Floods"

D.H. Merchant, Nov 2015

Ten CO₂ Tertiary Recovery Methods

Tertiary CO₂ Flooding

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States

1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost



Tertiary CO₂ Flooding

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States

1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost



Tertiary CO₂ Flooding

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States

1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost




2015's – CMTC 440075 – “Life Beyond 80 - A Look at Conventional WAG Recovery beyond 80% HCPV Injection in CO₂ Tertiary Floods”

Ten CO₂ Tertiary Recovery Methods

Tertiary CO₂ Flooding

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States

1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost




Conventional WAG w/ ROZ

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States

1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost


SPE Paper 138514 – “Life Beyond 80 - A Look at Conventional WAG Recovery beyond 80% HCPV Injection in CO₂ Tertiary Floods”



Gravity Drainage / Double Displacement

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States


1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost



Gas Cycling – Denbury Resources

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States

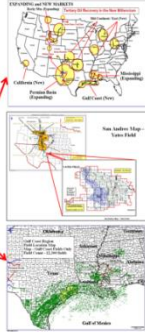
1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost



Huff-n-Puff (Single Well Injection)

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States


1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost



Heavy Oil (14+ API Gravity)

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States


1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost



Shale Oil – Bakken, Wolfcamp

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States

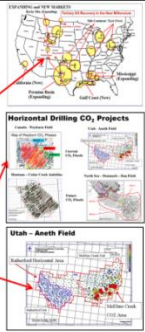
1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost



Horizontal Well Development

Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States


1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost



CO₂ Gas Drive w/ Nitro Boost

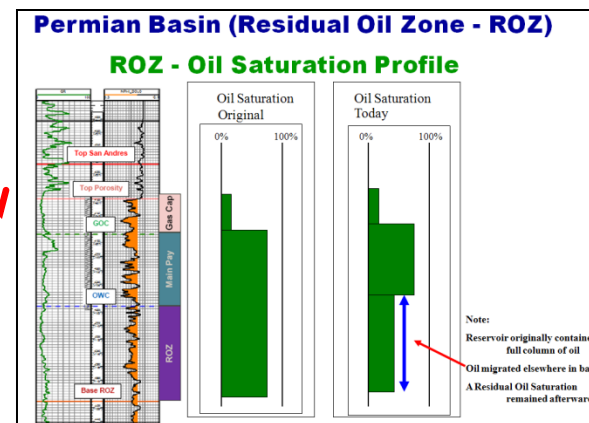
Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States

1. Conventional WAG Recovery (90%+)
2. Residual Oil Zone (ROZ) (Seminole)
3. Gravity Drainage (Yates Field)
4. Double Displacement (Yates Field)
5. Gas Cycling (Denbury, Mississippi).
6. Huff-and-Puff (100+ Projects)
7. Heavy Oil - Calif. (14+ API Gravity)
8. Shale Oil (Bakken) (Under Investigation)
9. Horizontal Well Pattern Development
10. CO₂ Gas Drive w/ Nitro Boost



Ten CO₂ Recovery Methods used for Tertiary Oil Recovery in the United States

- CMTC-502866-MS “The Look at Conventional WAG Injection Techniques developed from Lab in the 1950’s to 2017” deals strictly with Conventional Main Pay and ROZ Reservoirs**

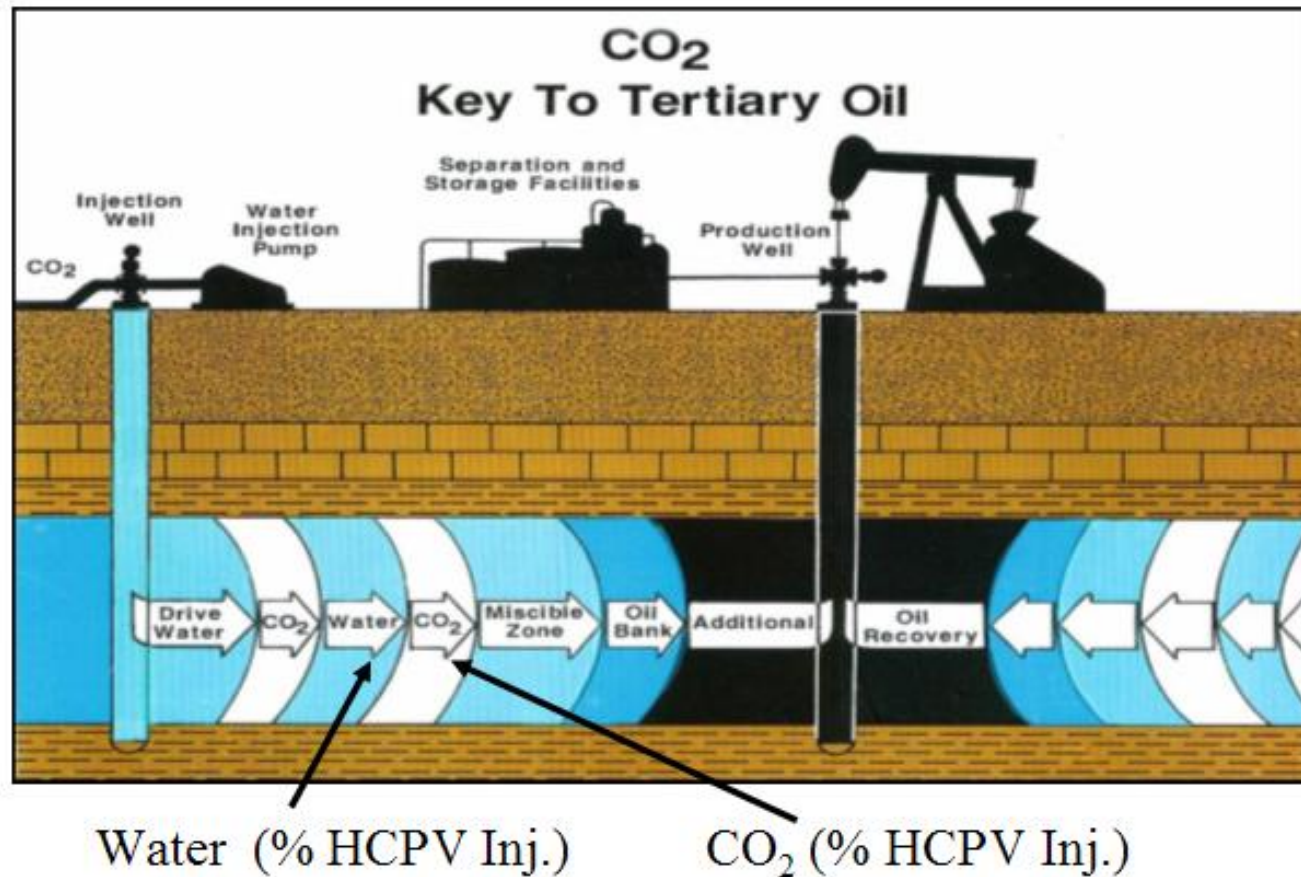


What is Conventional WAG Management?

Conventional Water Alternating Gas (WAG)

90% of all CO₂ floods to date

Conventional WAG Injection Techniques



Permian and Rocky Mountain Basins

History of “WAG”

1950's and 1960's

1950's – 150 Small Scale Miscible and Immiscible Projects

1958 - Lab Experiments Caudle and Dyes introduced water to decrease solvent mobility

1970's

1972 – Sacroc Unit (Kelly Snyder field) First Commercial Large Scale Project

1972-1979 North Cross, Two Freds, Maljamar, others

1980's Large Scale Permian Basin and Rocky Mountain Expansions

Slaughter field three projects plus Wasson ODC Unit – Amoco's Tapered WAG

Wasson field Denver Unit – Shell's Continuous Injection area plus DUWAG

Wasson field Willard Unit - Arco's Area Wide WAG went to Individual Patterns

Seminole field – Amerada Hess's Constant WAG scheme

Rangely field – Chevron's Wide Area WAG scheme

Bairoil (Lost Soldier and Wertz field) – Amoco's Tapered WAG

Aneth field - Horizontal Well Pattern Development – Constant WAG

1990's, 2000's, and 2010's

Most new CO₂ flood projects adopt the “Tapered WAG” approach to WAG Management

CO₂ Flooding in the United States

40+ Years of CO₂ Flood History

1980's – 1990's

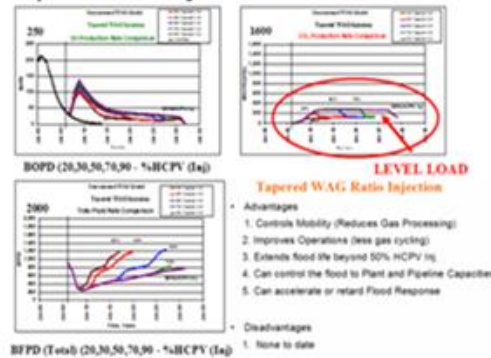
Field	State	Reservoir	Lithology	%HCPV Injected	Rec Eff. % OOI	Gross Utilization, Mcf/Bbl	Net Utilization, Mcf/Bbl
Field Scale							
Dollarhide	Texas	Devonian	Tripart Chert	30	14		2.4
East Vacuum	Texas	San Andres	Oolitic Dolomite	30	8	11.1	6.3
Ford Geraldine	Texas	Delaware	Sandstone	30	17	9	5
Means	Texas	San Andres	Dolomite	55	7.1	15.2	11
North Cross	Texas	Devonian	Tripart Chert	40	22	18	7.8
Northeast Purdy	Oklahoma	Springer	Sandstone	30	7.5	6.5	4.6
Rangely	Colorado	Weber	Sandstone	30	7.5	9.2	5
Sacroc (17 Pattern)	Texas	Canyon Reef	Carbonate	30	7.5	9.7	6.5
Sacroc (4 Pattern)	Texas	Canyon Reef	Carbonate	30	9.8	9.5	3.2
South Welch	Texas	San Andres	Dolomite	25	7.6		
Two Freds	Texas	Delaware	Sandstone	40	15.6	15.6	8
Wertz	Wyoming	Tensleep	Sandstone	60	10	13	10

SPE 18977 Brock and Bryon 1989

7% to 12% OOIP Rec
30% to 40% HCPV Inj

2000's

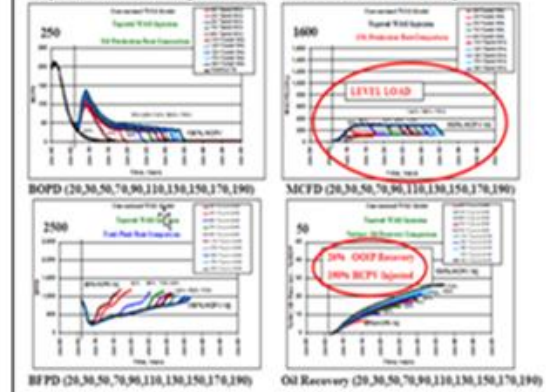
Tapered WAG Injection



18% OOIP Rec
80% HCPV Inj

2010's

Tapered WAG Injection – to 190% HCPV Inj

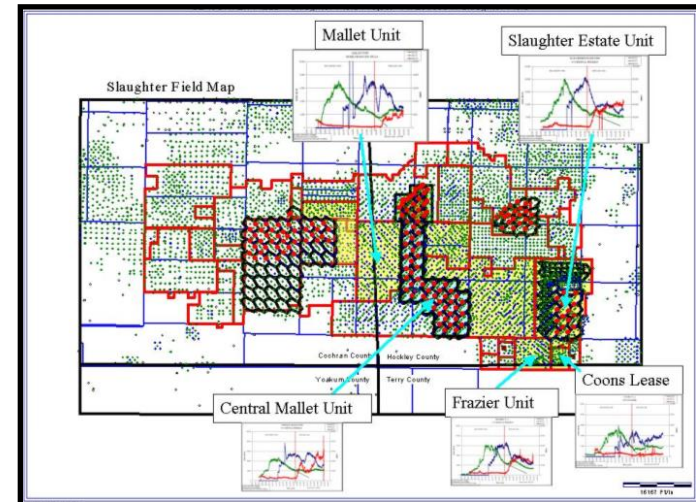
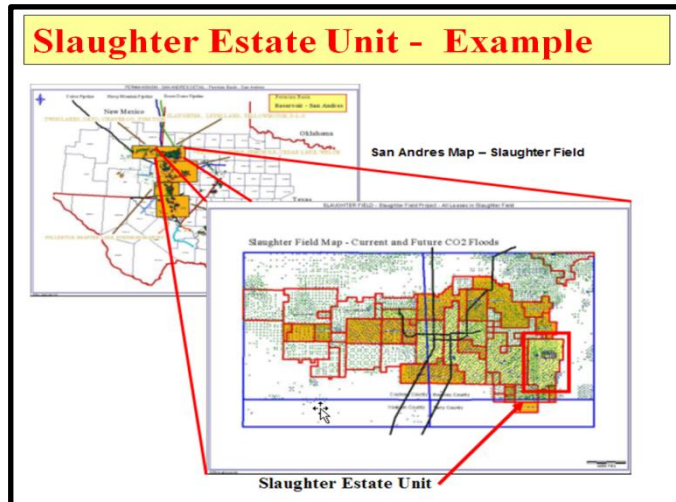


20% to 26% OOIP Rec
140% to 190% HCPV Inj

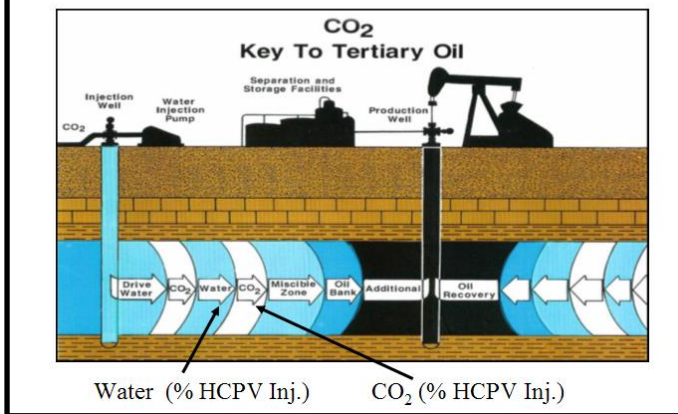
Note: Not all fields will achieve this

Look at how far have we come?

What is Conventional WAG Management?



Conventional WAG Injection Techniques



Definitions WAG Process

Slaughter Estate Unit

5 - Spot and
Chickenwire
Well Patterns



Pattern Parameters

- Original Oil-in-Place - Amount of Oil in Place (Standard conditions)
- HCPV - Amount of Oil in Place (Reservoir conditions)
- Total Slug Size - Total Amount of CO₂ Inj. (20-100+ % HCPV)
- Half Cycle CO₂ Slug Size - HCPV of CO₂ Inj in one cycle (0.25 - 30.00 %)
- Water Cycle CO₂ Slug Size - HCPV of H₂O Inj in one cycle (0.25 - 10.00 %)
- WAG Ratio - Ratio of Half cycle Water to Half cycle CO₂
- GWR Ratio - Ratio of Half cycle CO₂ to Half cycle H₂O

CO₂ Tertiary floods are designed to operate best in fields that have been drilled on 5-spot, 9-spot, or Chicken-wire development patterns

DIFFERENT OPERATORS

DIFFERENT PHILOSOPHIES (Reservoir Driven)

- Continuous CO₂ - Continuously inject CO₂ (No water)
- Constant WAG - example - 1:1 WAG with (1.0 % CO₂, 1.0% H₂O)
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 % CO₂, 0.10 % H₂O) for 5% HCPV
WAG (1.0 % CO₂, 0.50 % H₂O) for 10% HCPV
WAG (1.0 % CO₂, 1.00 % H₂O) for 20% HCPV
WAG (1.0 % CO₂, 2.00 % H₂O) for 30% HCPV
Chase Water Injection

**“Wetting the
WAG”**



Note: Total Slug Size = 85% HCPV Inj. Of CO₂

Amoco WAG Management – 1980's

Tapered WAG Injection

Reservoir Simulation

SPE Paper 26624 - Reservoir Management in Tertiary CO₂ Floods



Figure 1. Field Location Map

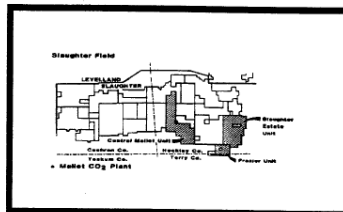


Figure 2. Active CO₂ Floods
In Slaughter Field

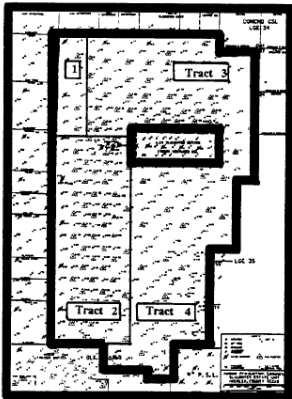


Figure 3. Slaughter Estate Unit
Base Map

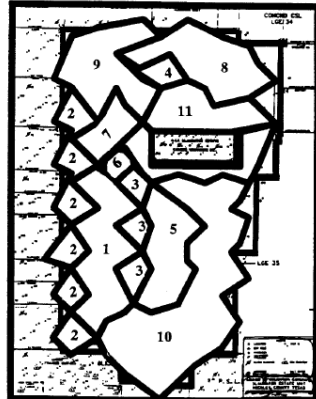


Figure 4. Slaughter Estate Unit
Model Segment Map

10

RESERVOIR MANAGEMENT IN TERTIARY CO₂ FLOODS

SPE 26624

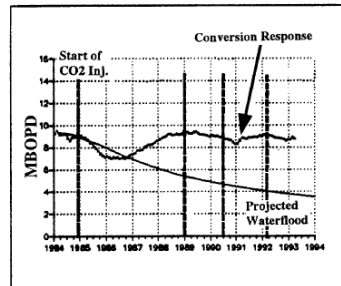


Figure 6a. Oil Production Rate - MBOPD

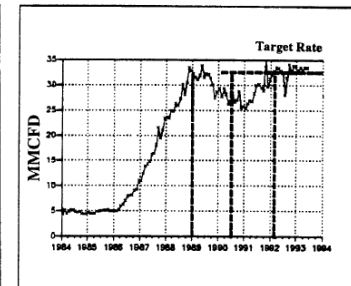


Figure 6b. Gas Production Rate - MMCFD

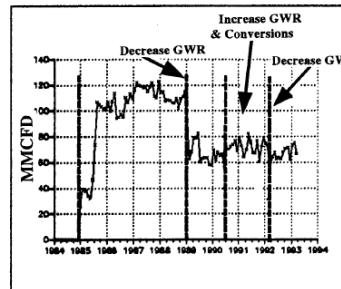


Figure 6c. CO₂ Injection Rate - MMCFD

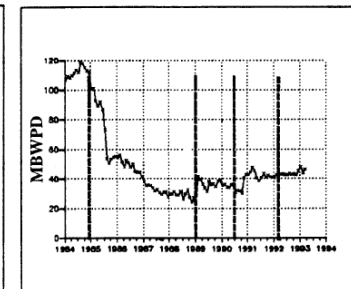


Figure 6d. Water Injection Rate - MBWPD

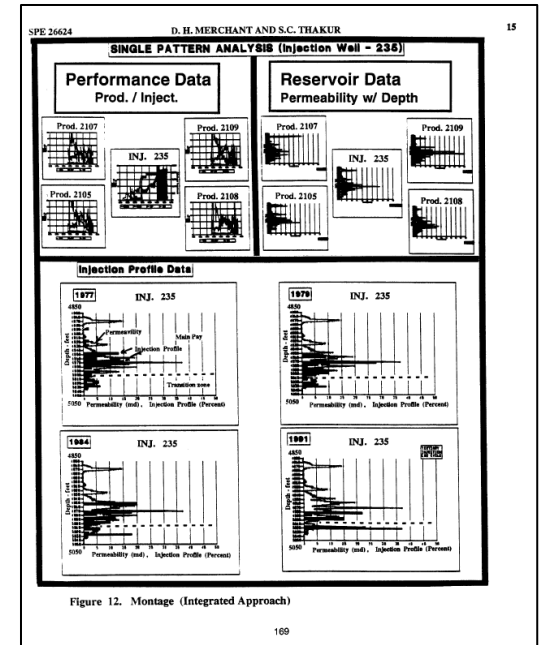
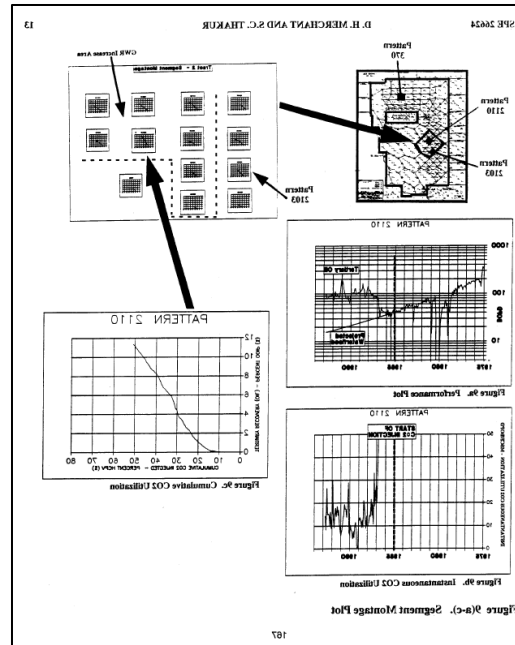
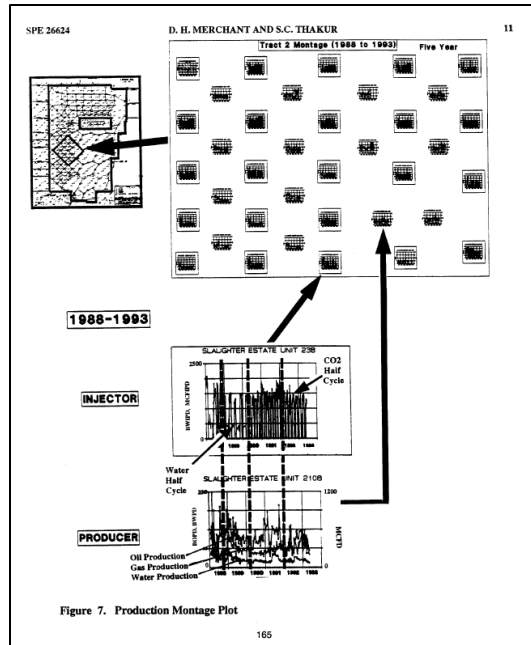
Figure 6(a-d). Slaughter Estate Unit Tertiary Performance

Reservoir Simulation was a vital tool in understanding
the WAG Process

Amoco WAG Management – 1980's

Tapered WAG Injection

SPE Paper 26624 - Reservoir Management in Tertiary CO₂ Floods



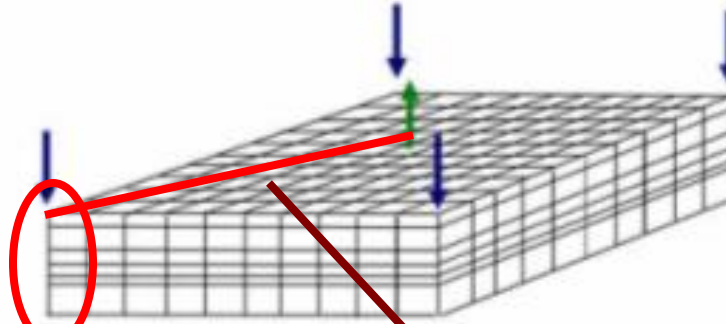
Production Montage

Pattern Montage

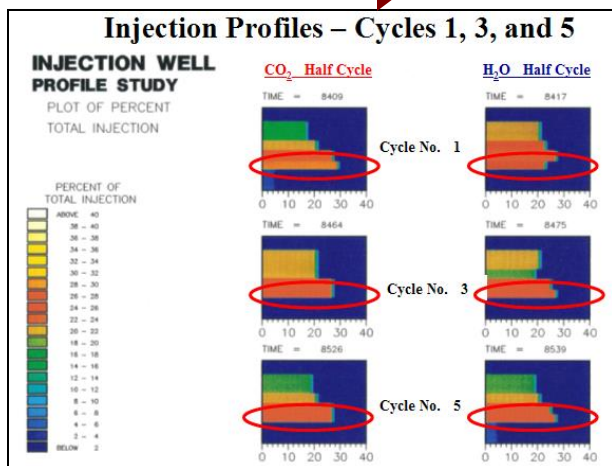
Integrated Montage

Reservoir Simulation

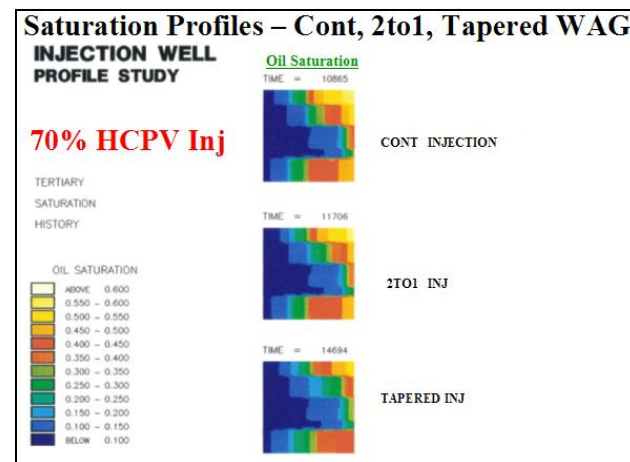
Reservoir Model Study - San Andres 5 Spot Single 5 Spot Pattern (10X10X6 Grid)



Injection Profiles

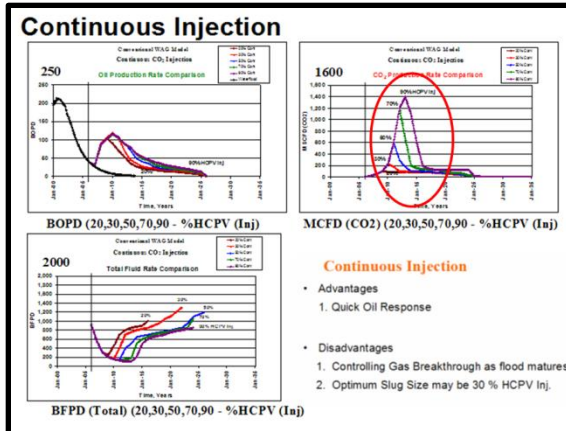


X-Cross Section - Oil Saturation

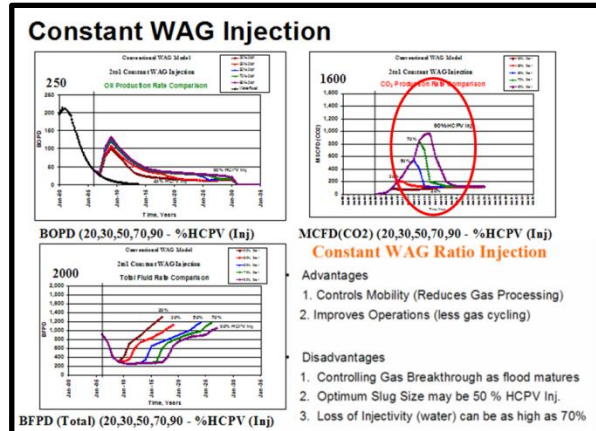


Reservoir Simulation

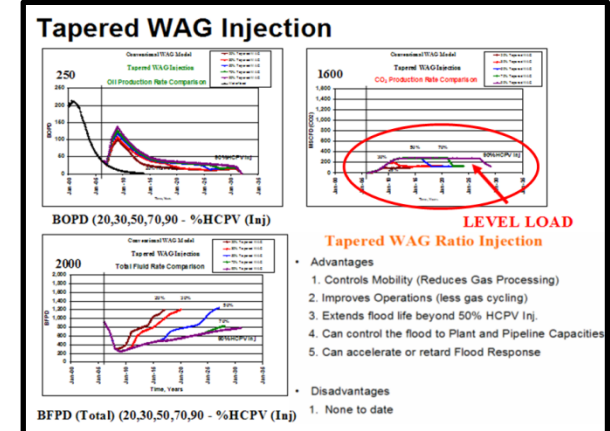
Continuous



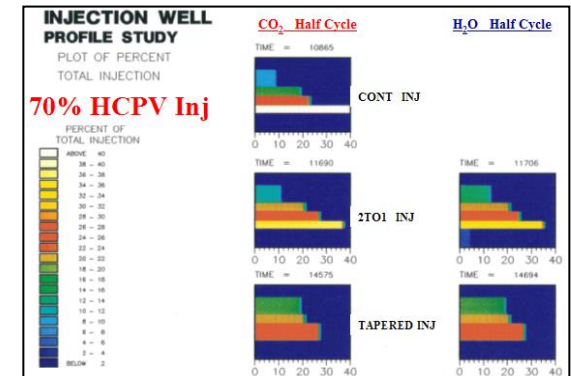
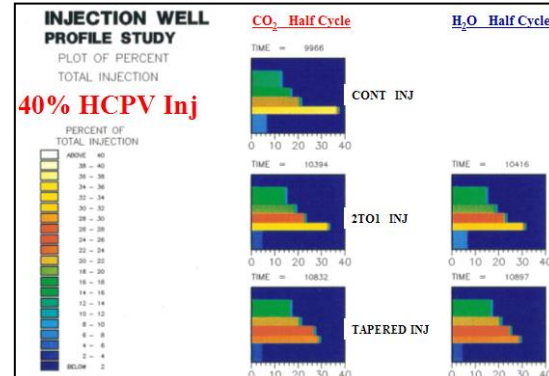
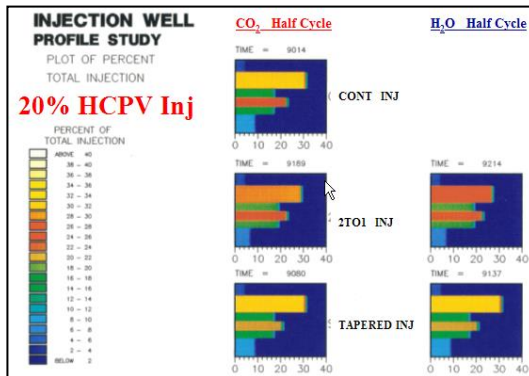
Constant WAG



Tapered WAG



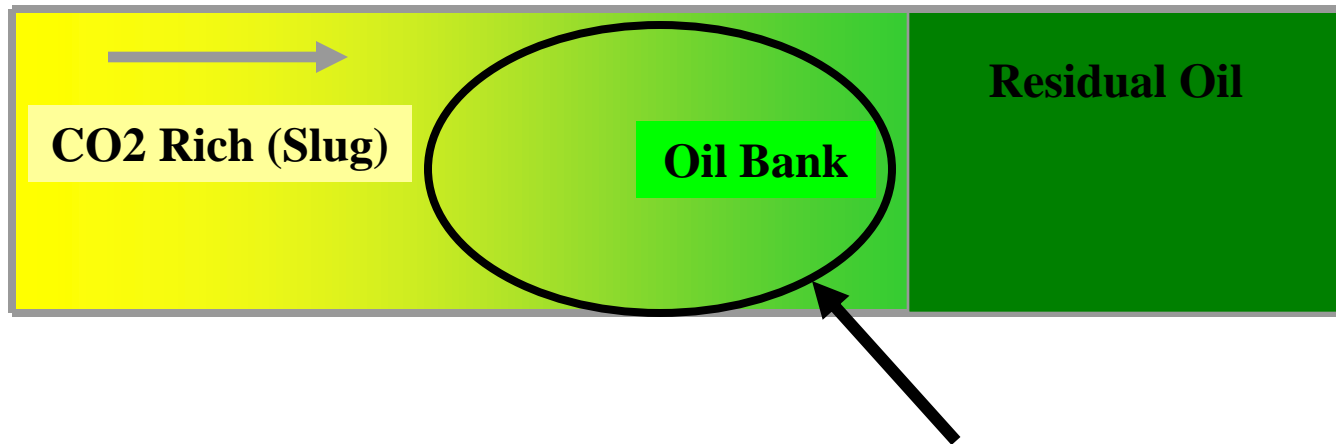
Injection Profiles – 20% HCPV to 70% HCPV



Tapered WAG provides Mobility Control in the Fast Zones

CO₂ Miscible Process Compositionally Driven

Oil Bank Transition Zone



Multiple Contact Miscible Process
(time and compositionally dependent)

Miscible Zone formed by CO₂
becoming enriched with C₂ – C₃₀

You can't fool Mother Nature.....

CO₂ Miscible Process Compositionally Driven

Oil Bank Transition Zone

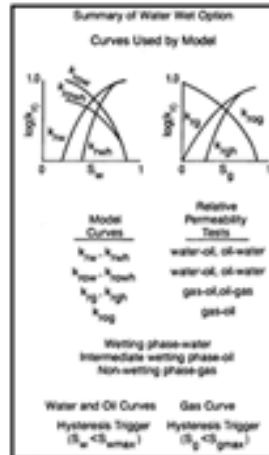


Multiple Contact Miscible Process
(time and compositionally dependent)

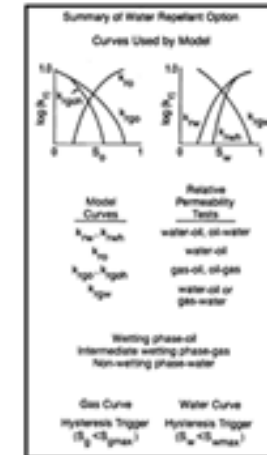
Miscible Zone formed by CO₂
becoming enriched with C₂ – C₃₀

CO₂ Trapping of the Non-wetting Phase and Relative Permeability

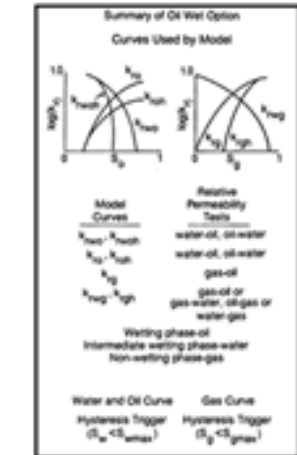
Water Wet - Sandstones



Intermediate Wet - Both



Oil Wet - Dolomites, Limestone



Note: Tertiary Oil Recovery and CO₂ trapping is governed by Relative Permeability Hysteresis of the non-wetting phase.

The amount of **CO₂ TRAPPED, STORED, OR SEQUESTERED** is dependent on the Composition of the Residual Oil Saturation and Phase Trapping of the Non-Wetting Phase, which in this case is CO₂.

Tertiary CO₂ Flooding

“The Previous Millennium”

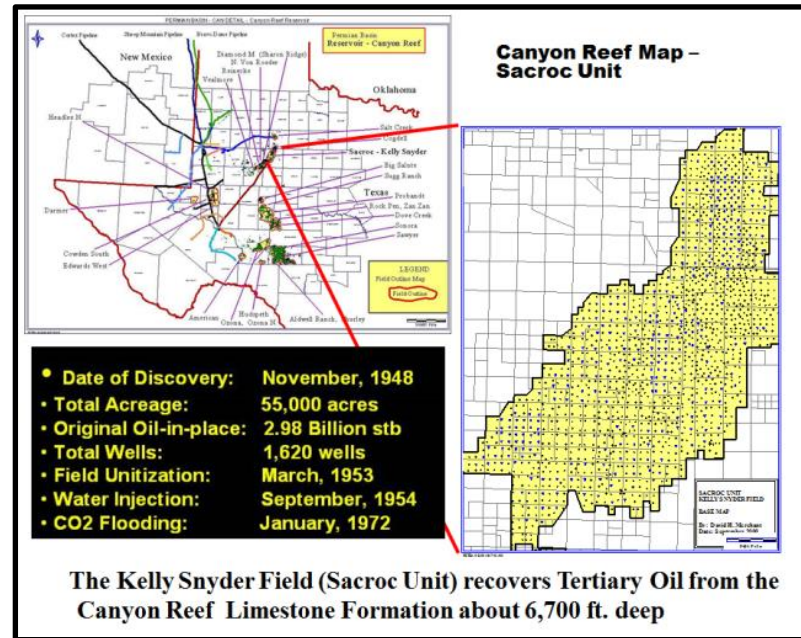
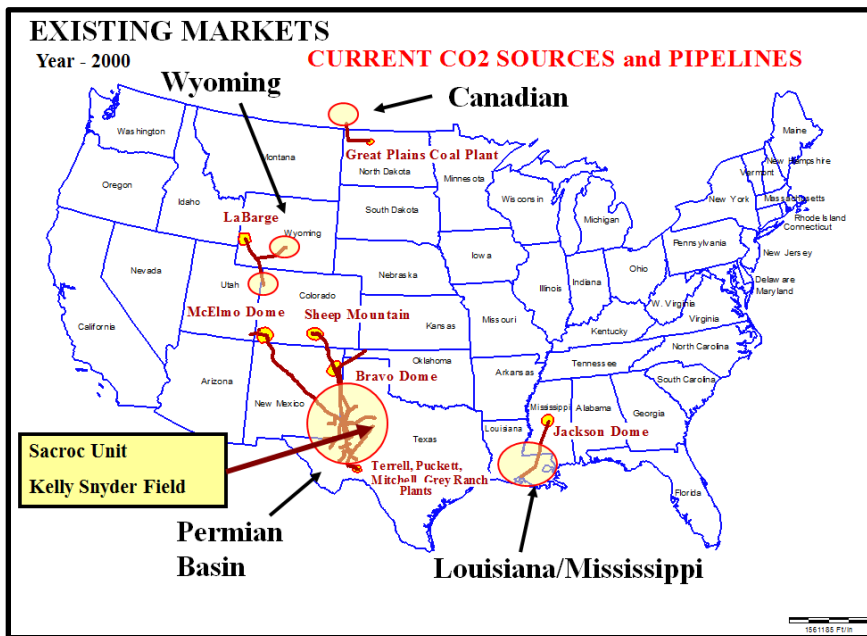
20th Century (1972 to 2000)

“Life below 80% HCPV Injected”

Permian Basin - 1970's

“First Commercial CO₂ Flood - 1972”

Sacroc Unit in Kelly Snyder Field

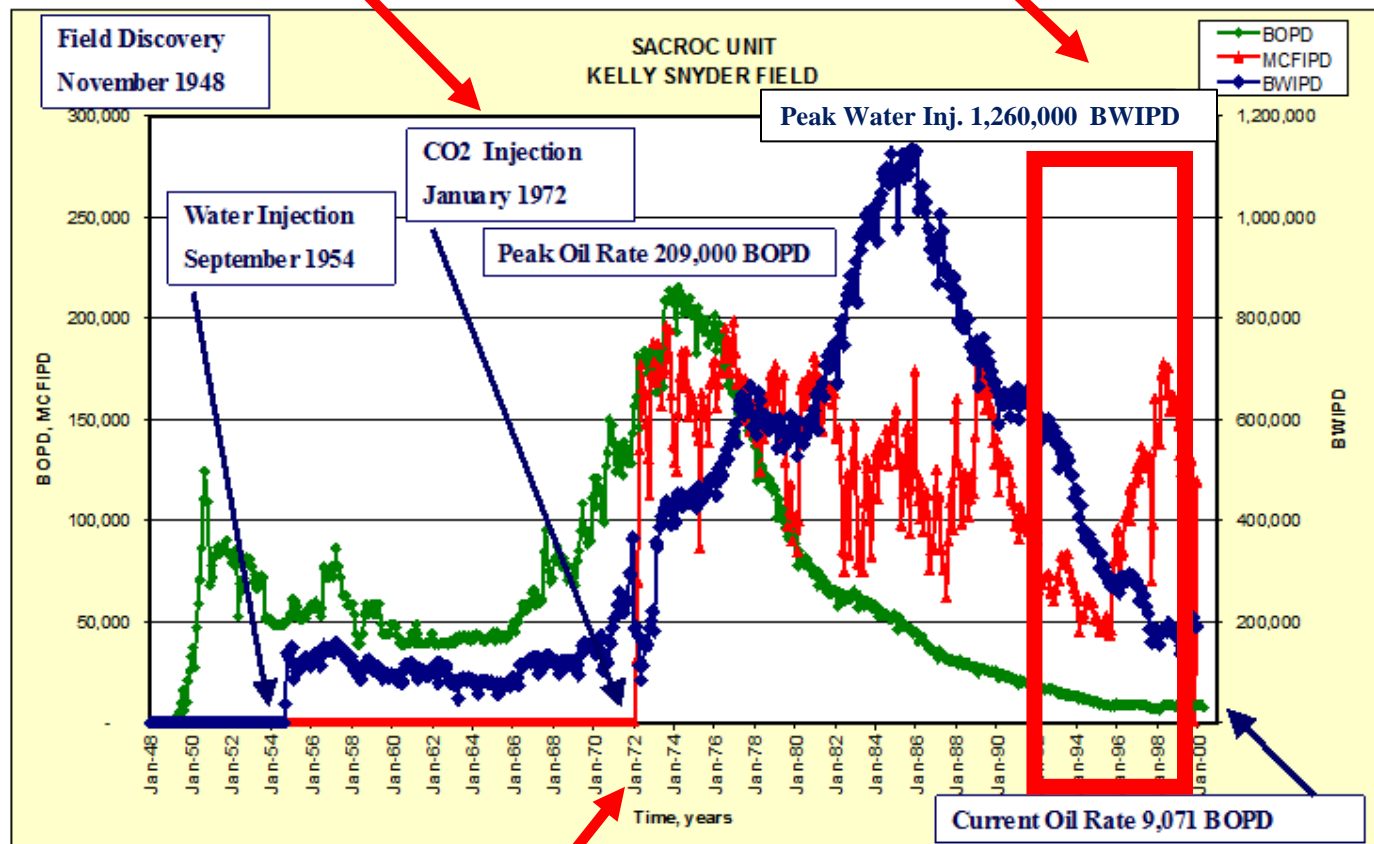


Sacroc Unit – Historical Performance

Chevron Ownership Pennzoil Operatorship

First Commercial CO₂ flood in 1972

1992 - 1999



Kinder
Morgan
Operatorship
2000 to
Present

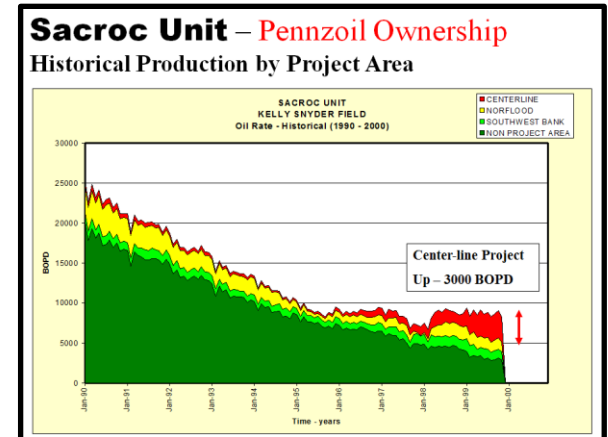
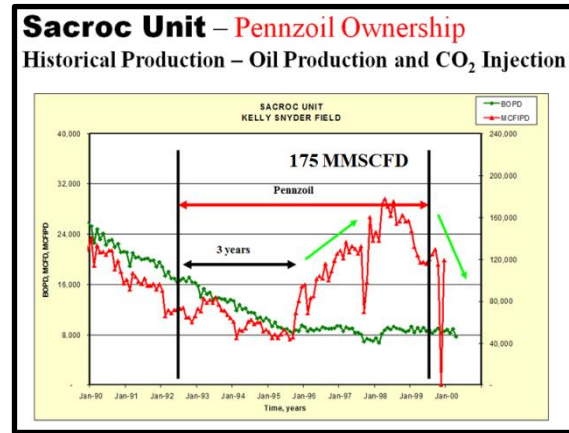
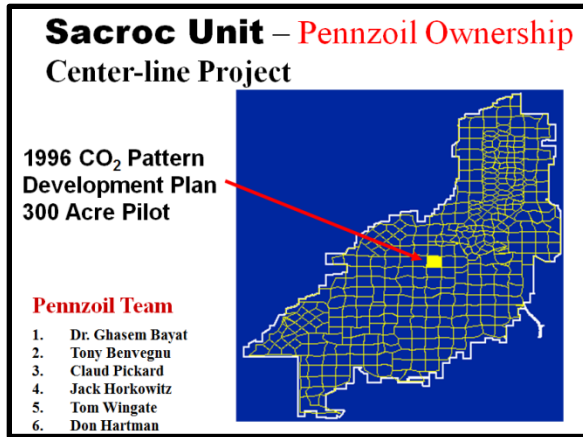
Waterflood Injection
Startup - 1955

Waterflood Injection Expansion
CO₂ Startup - 1972

Devon Operatorship
1999 - 2000

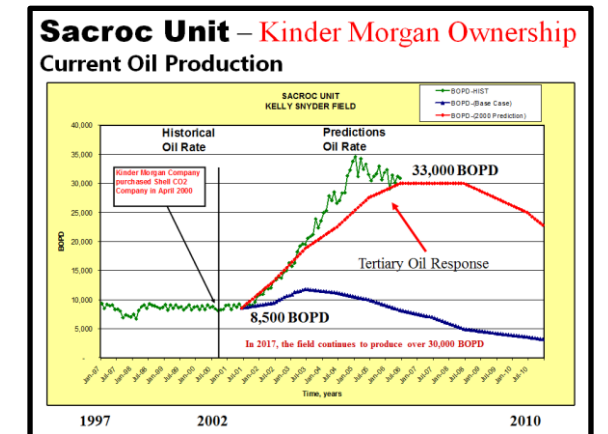
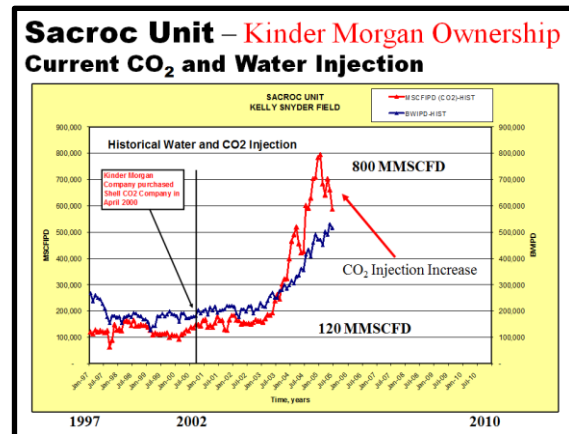
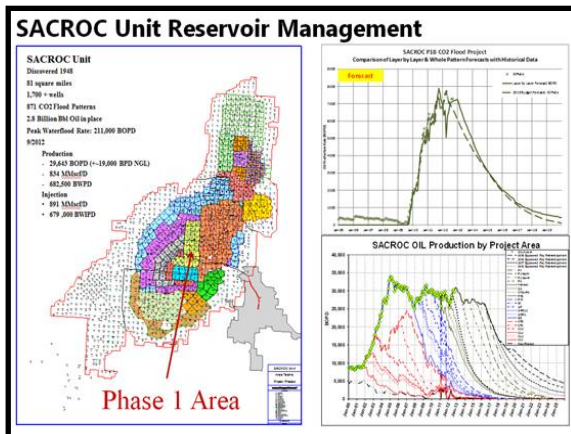
Sacroc Unit – Historical Performance

Pennzoil Operatorship (1992-1998)



Pennzoil implemented a 300 acre Centerline Pilot Project in 1996 which produced 1/3 of the total field's production over the total 55,000 acre unit boundary

Kinder Morgan Operatorship (2000 -Present)

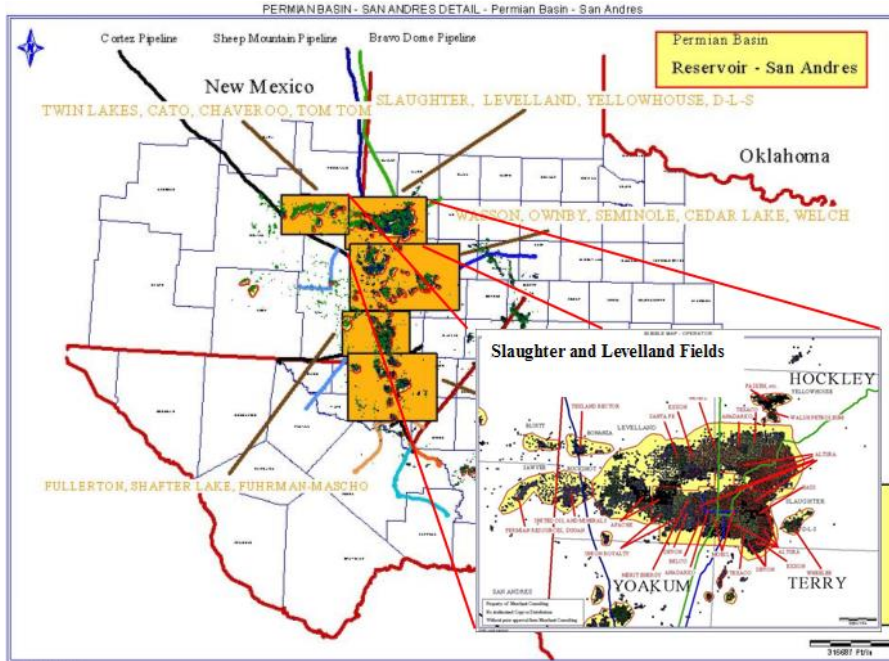


Kinder Morgan implemented a phased-in Tertiary Development Plan and expanded CO₂ Injection to over 800 MMSCFIPD with a 30,000 BOPD Response WAG Management is on an Individual Pattern Basis with Multiple Pattern Development programs developed to date

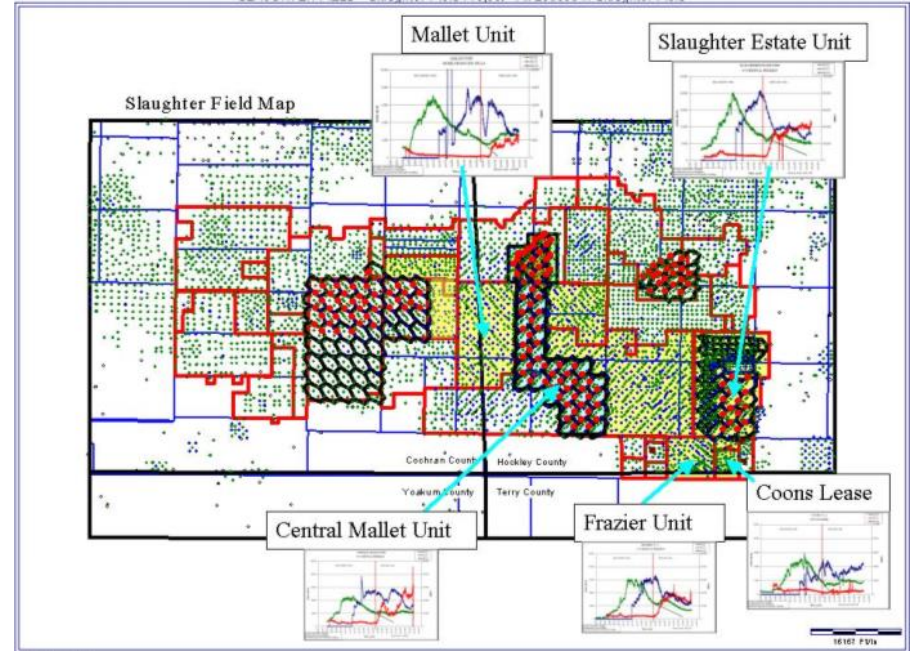
1980's Tertiary CO₂ Flooding

Permian Basin (Slaughter and Levelland Fields)

Slaughter and Levelland Fields



Slaughter Field

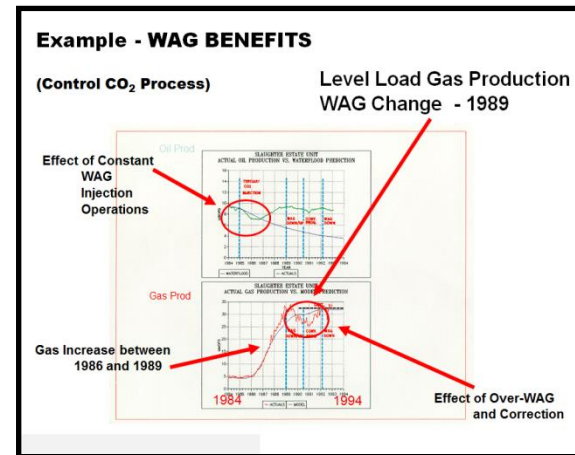
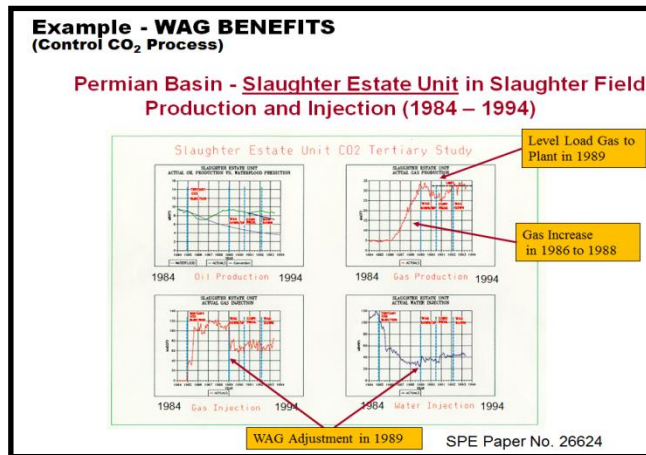
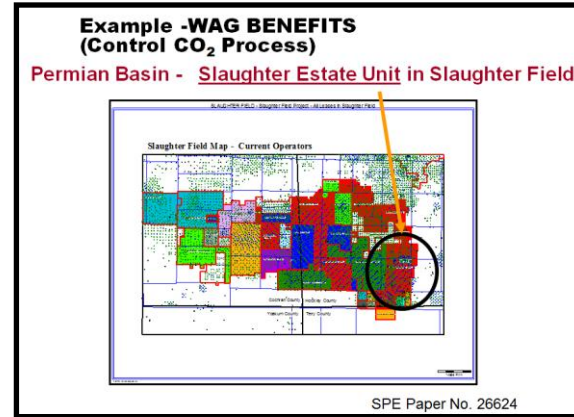
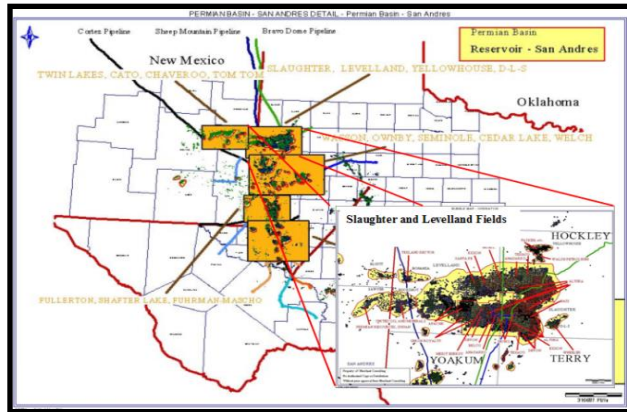


The Slaughter and Levelland fields recover Tertiary Oil from the San Andres Formation about 5,000 ft. deep from various leases and operators located across both fields.

1980's

Permian Basin - Slaughter Estate Unit

Amoco's Tapered WAG Management (SPE 26624)



In 1989, Amoco converted from Constant WAG to Tapered WAG Management which provided the means to “Level Load” gas production to the Plant Inlet Gas Rate thus allowing control over the CO₂ Process.

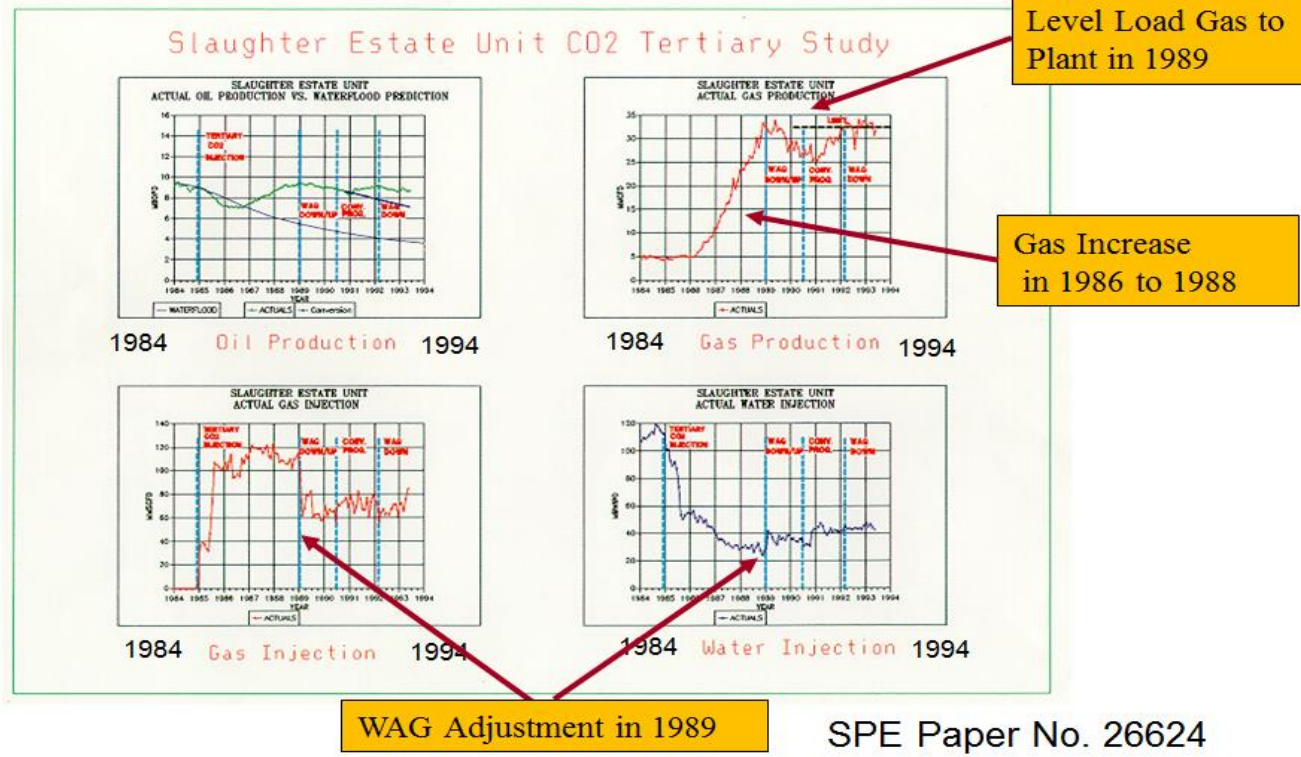
1980's

Example - WAG BENEFITS (Control CO₂ Process)

Permian Basin - Slaughter Estate Unit in Slaughter Field Production and Injection (1984 – 1994)

Amoco Team

Kevin McCollough
Steve Pennell
Burt Nelson
John Kimberling
David Merchant



Amoco initiated a WAG increase in 1989 that “Level Loaded” gas production to the Plant Inlet Rate, which provided the ability to control gas production throughout the life of the flood, thus advancing CO₂ tertiary recovery beyond the 8% to 12% OOIP documented in most studies.

1980's

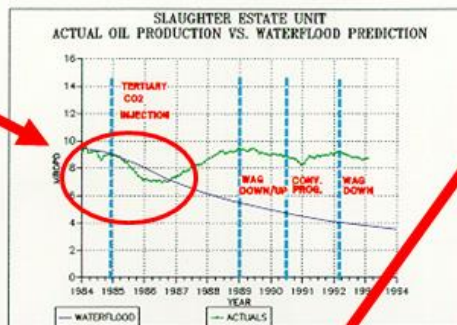
Example - WAG BENEFITS

(Control CO₂ Process)

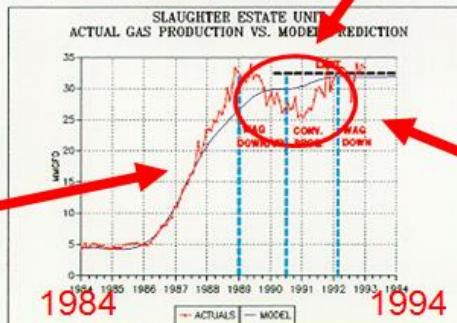
Level Load Gas Production
WAG Change - 1989

Effect of Constant
WAG
Injection
Operations

Oil Prod



Gas Prod



Gas Increase between
1986 and 1989

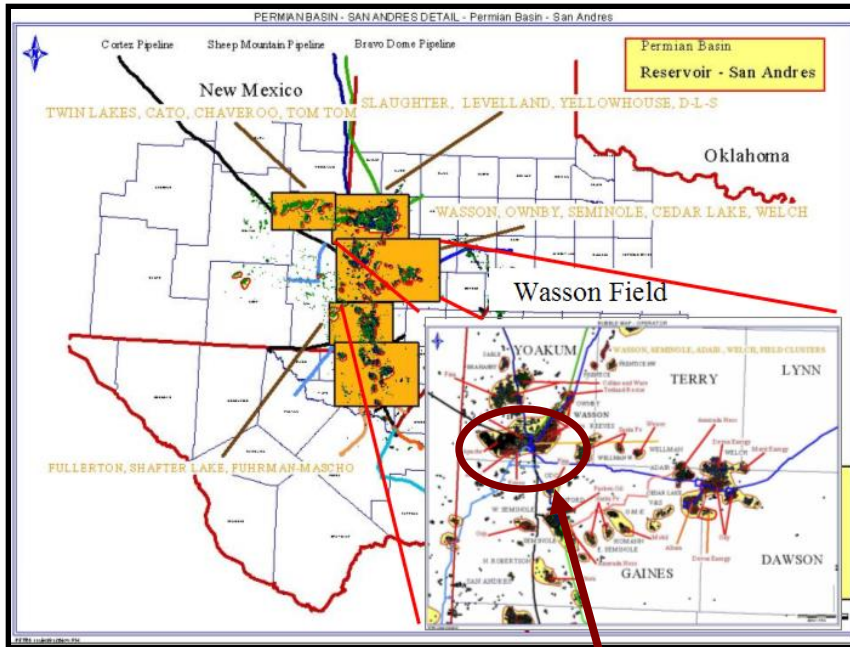
Effect of Over-WAG
and Correction

Amoco's Tapered WAG Management provided the means to "Level Load" gas production to the Plant Inlet Rate, but "Over-WAGGED" causing the gas production to be less than inlet rate. To compensate Amoco then initiated individual pattern WAG adjustments to better fine tune gas production back to plant inlet rate

1980's Tertiary CO₂ Flooding

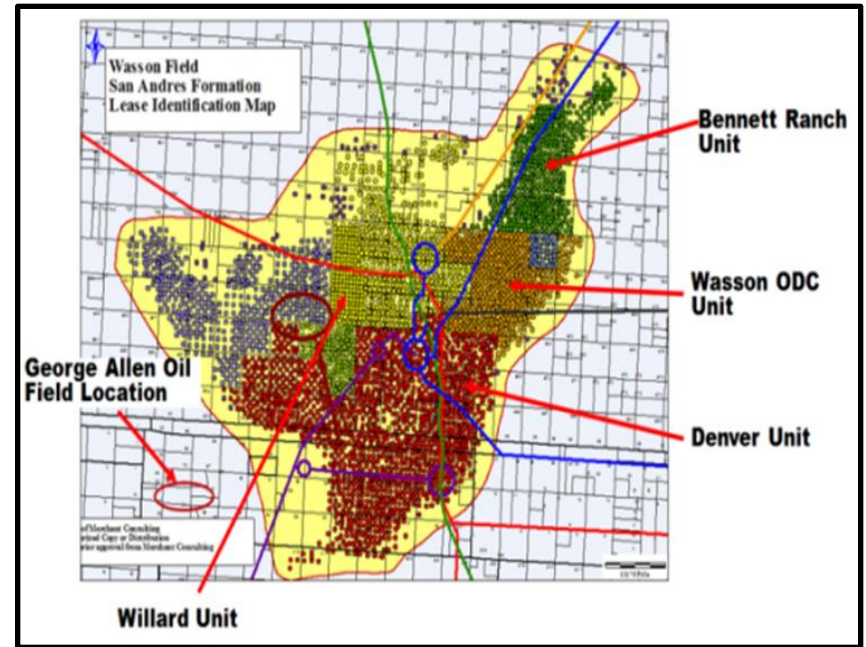
Permian Basin (Wasson Field)

Wasson Field Location



Wasson Field

Wasson Field



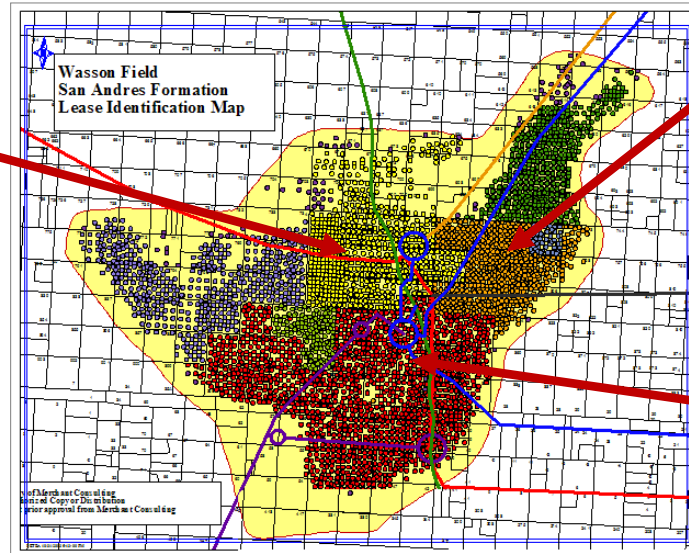
The Wasson field recovers Tertiary Oil from the San Andres Formation about 5,500 ft. deep from various leases and operators located across this large field and contains a large Residual Oil Zone (ROZ).

1980's Tertiary CO₂ Flooding

Permian Basin (Wasson Field)

**Willard Unit
(Arco)**

Original
9-Spot Pattern
Development



**Wasson ODC Unit
(Amoco)**

**Denver Unit
(Shell)**

The Denver Unit, operated by Shell, initiated a Continuous Injection Area targeting 4% CO₂ HCPV/year and a WAG Injection area (DUWAG) where they operated 2% HCPV/year CO₂ and 2% HCPV/year. The Continuous Area was converted to a Line Drive due to conformance orientation issues.

The Wasson ODC Unit, operated by Amoco initiated a WAG down with Amoco's "Tapered WAG" operating scheme in 1989 to "Level Load" gas to the plant inlet rate.

The Willard Unit, operated by Arco initiated early on Large Area Pattern Switches, but later changed to an individual pattern approach.

1980's

What are they doing?

CO₂ Tertiary Flood Management

Pattern Review In Progress: Control Central



1. Evaluating Individual Well Performance
2. Evaluating Individual Pattern Performance
3. Making WAG Adjustments based on Pattern Performance

Tertiary CO₂ Flooding

“The New Millennium”

21st Century (2000 and beyond)

“Life beyond 80% HCPV Injected”

The New Millennium

EXPANDING and NEW MARKETS

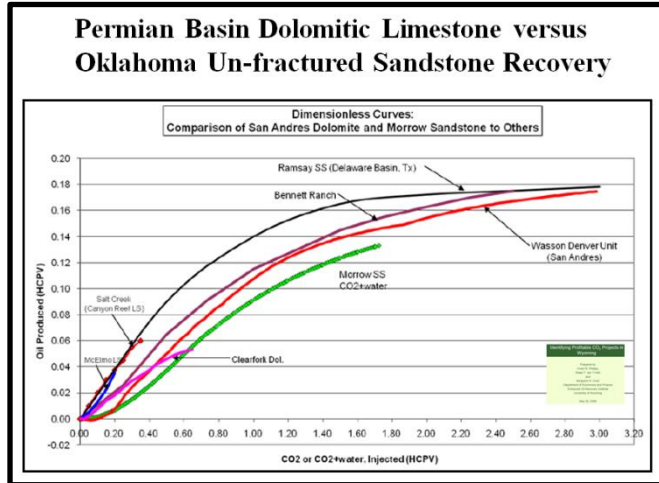
CURRENT CO2 SOURCES and PIPELINES



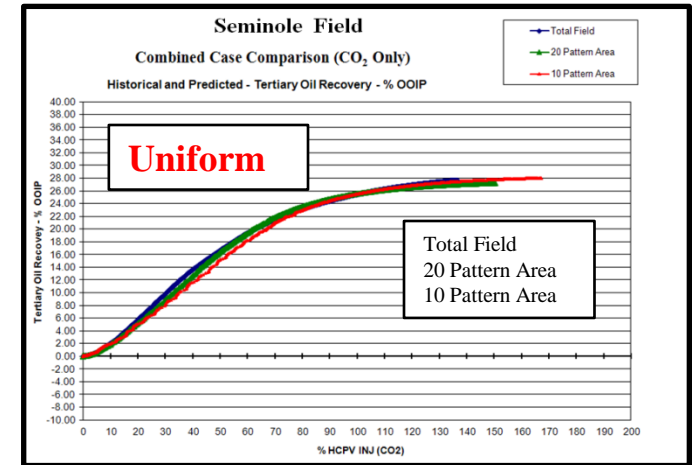
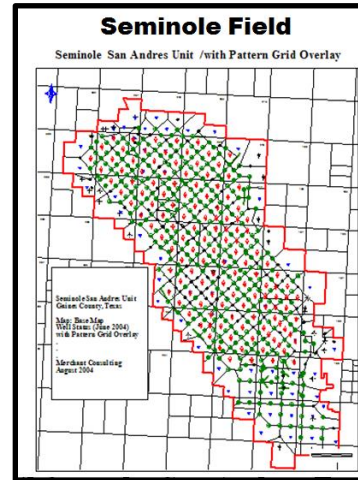
Tertiary Oil Recovery

%OOIP Rec versus %HCPV Inj

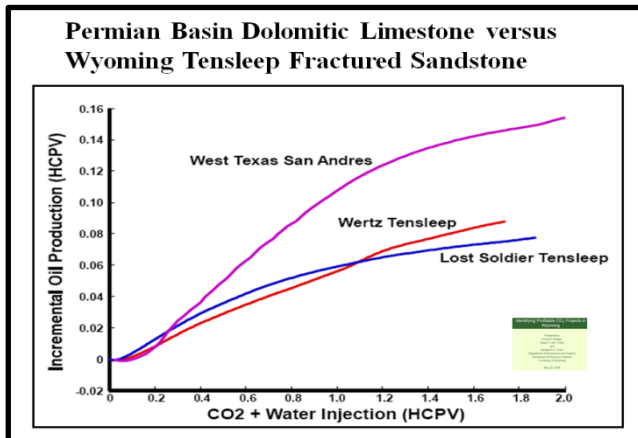
Un-fractured Sandstone versus Dolomite



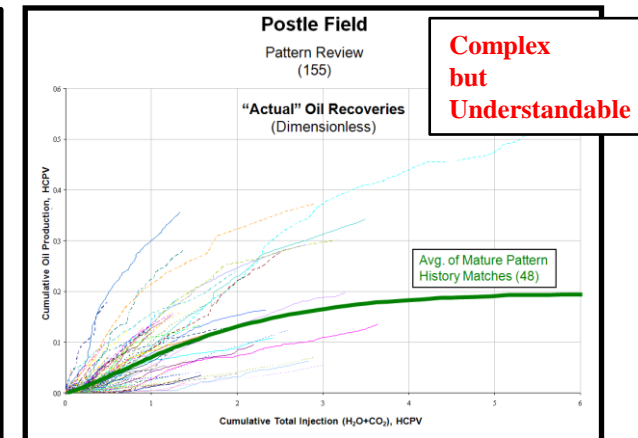
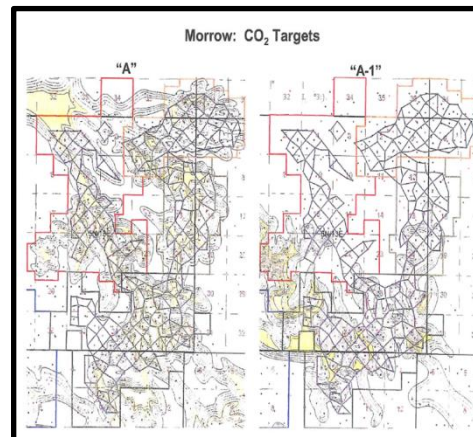
Homogeneous Dolomite – Seminole Unit



Fractured Sandstone versus Dolomite



Non-Uniform Pattern Sandstone – Postle field

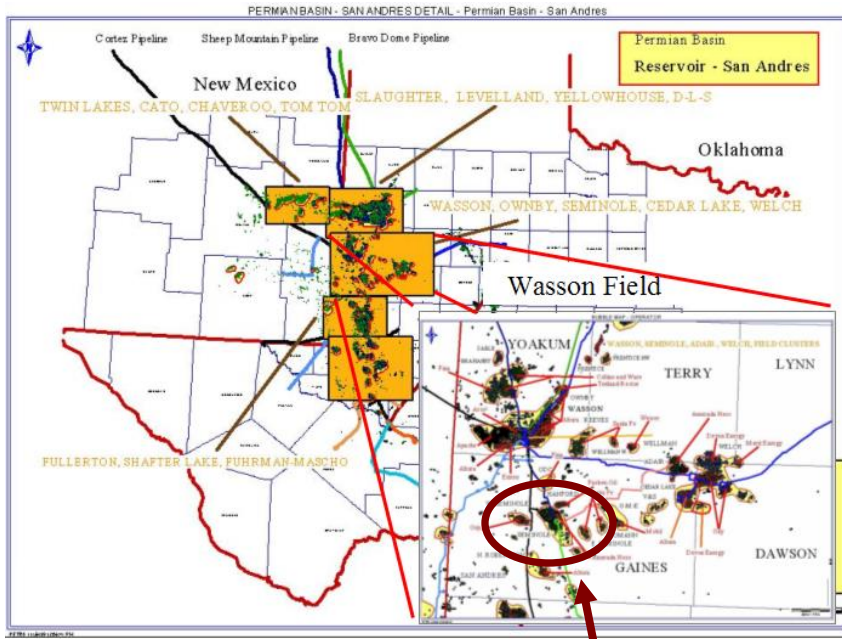


Not all Patterns and Reservoirs are alike

1980's Tertiary CO₂ Flooding

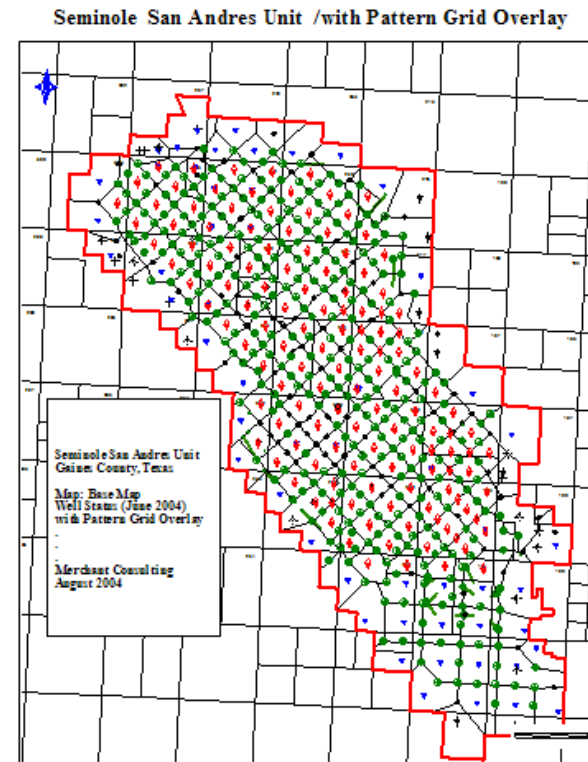
Permian Basin (Seminole Field)

Seminole Field Location



Seminole Field

Seminole Field

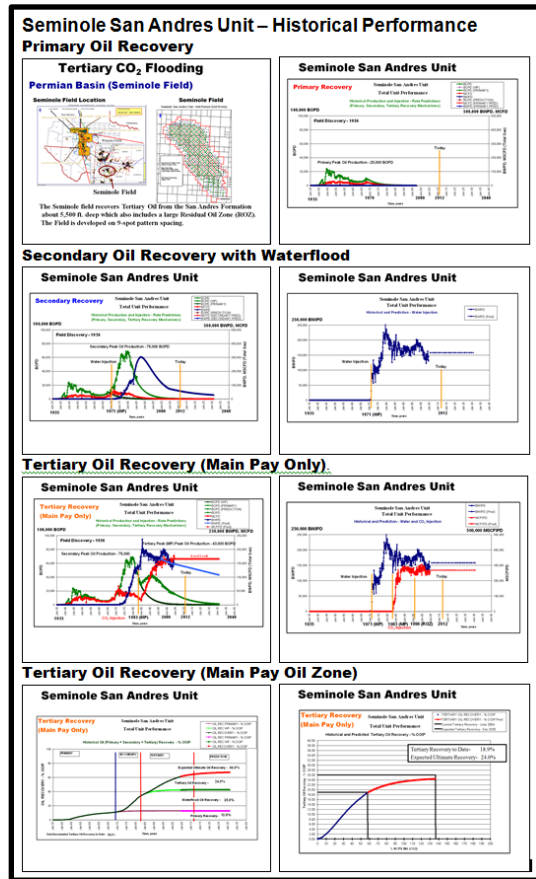


The Seminole field recovers Tertiary Oil from the San Andres Formation about 5,500 ft. deep which also includes a large Residual Oil Zone (ROZ). The Field is developed on 9-spot pattern spacing.

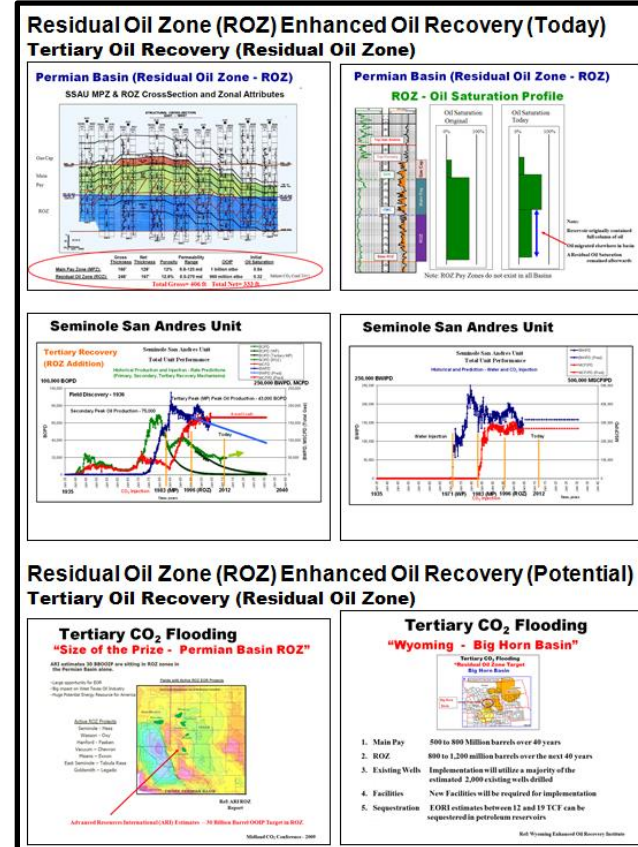
1980's Tertiary CO₂ Flooding

Permian Basin (Seminole Field)

Main Pay Performance



ROZ Performance



ROZ
30
Billion
OOIP
Barrel
Target

Since CO₂ Startup in 1983 Tertiary Oil Recovery is expected to recover 24% OOIP

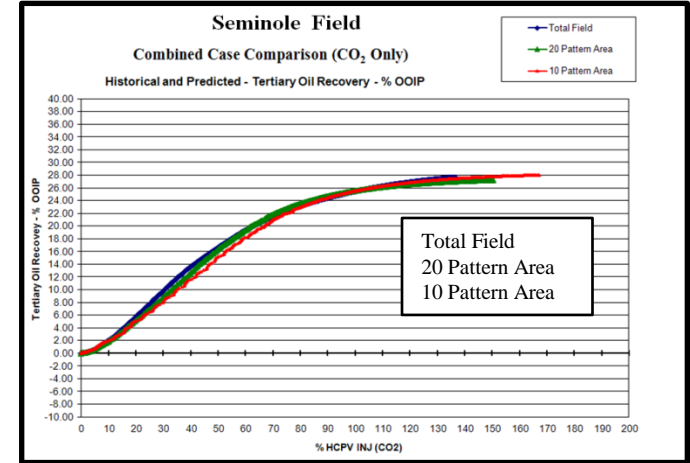
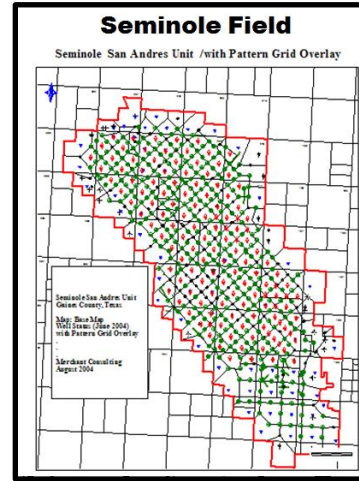
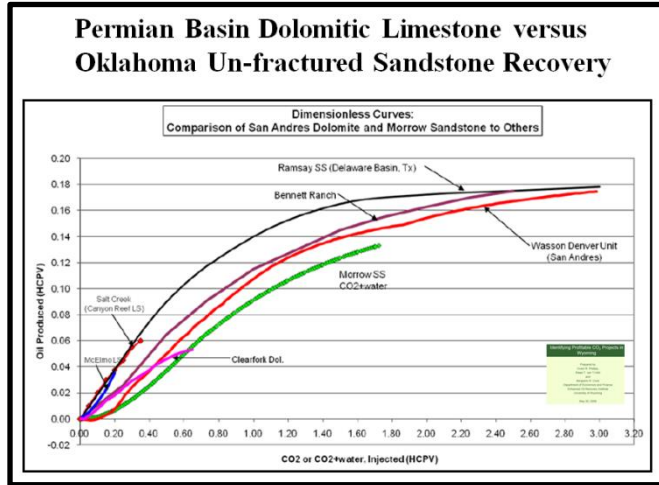
Since ROZ CO₂ Startup in 1996 Tertiary Oil Response had been excellent with expected ROZ Tertiary Oil Recovery comparable or better than Main Pay Tertiary Oil Recovery

Rocky Mountain Region

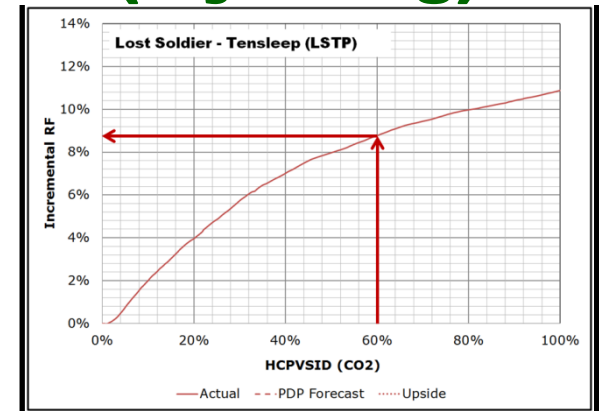
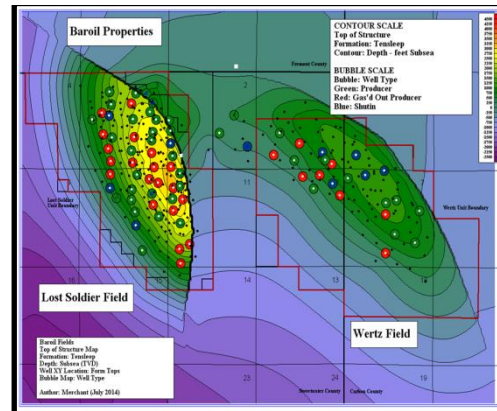
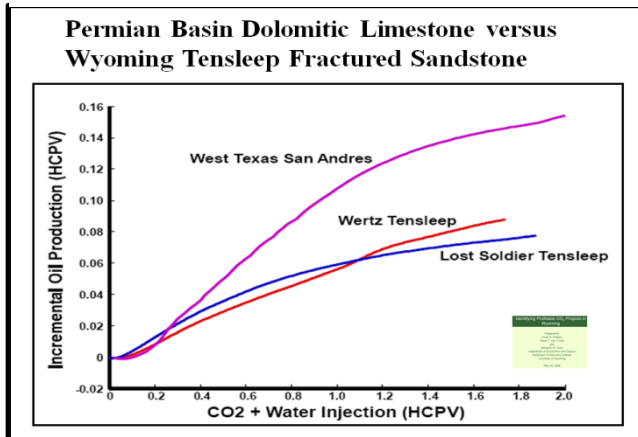
Seminole San Andres Unit (Permian Basin)

Un-fractured Sandstone versus Dolomite

Homogeneous Dolomite – Seminole Unit



Bairoil Field – Lost Soldier and Wertz (Wyoming)

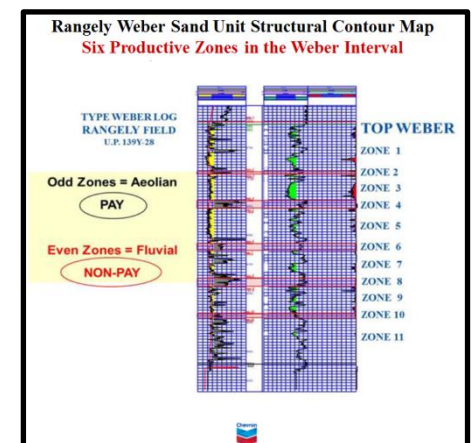
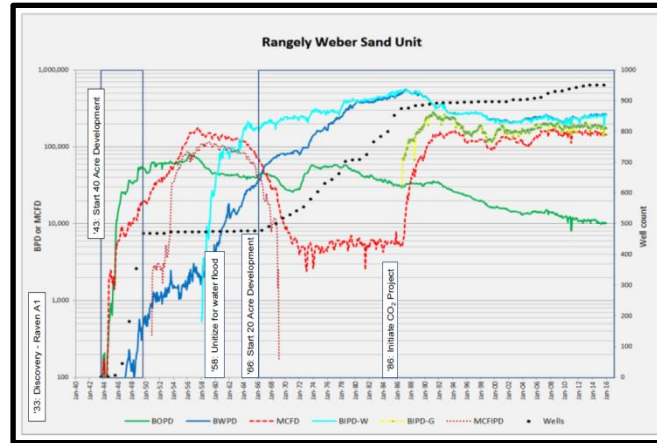
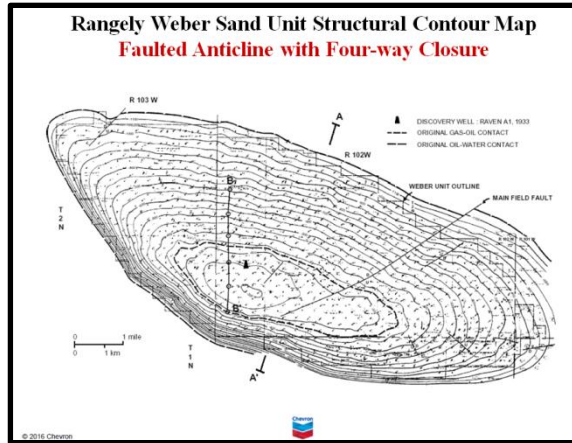


Not all Reservoirs are alike

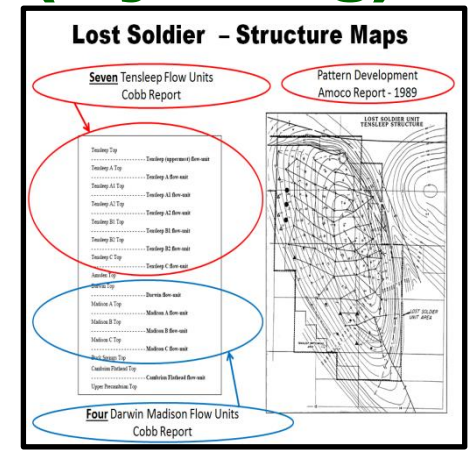
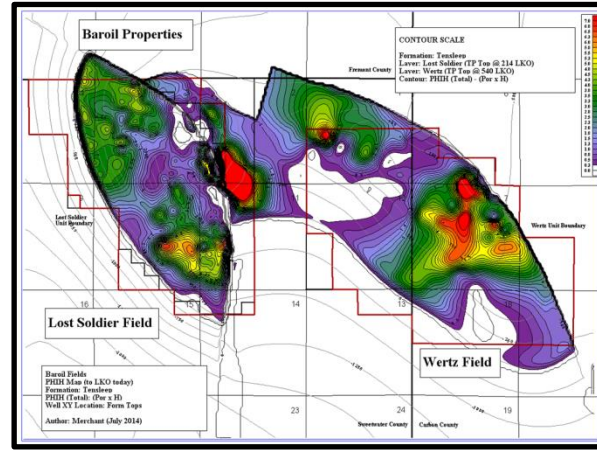
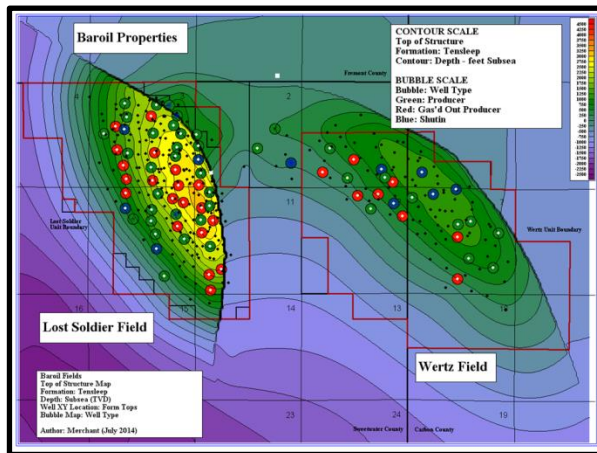
Rocky Mountain Region

Rangely Weber Unit – (Colorado)

Comparison



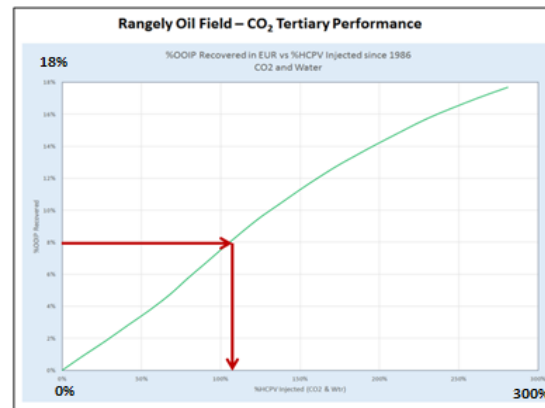
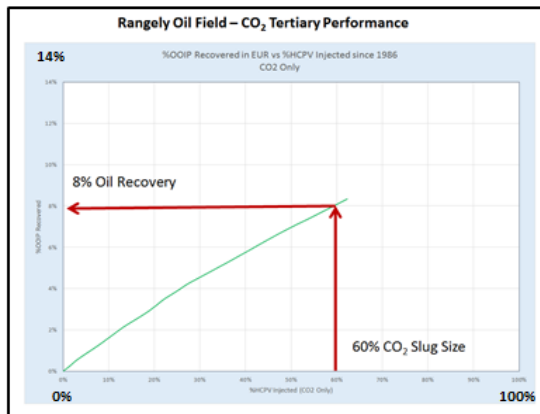
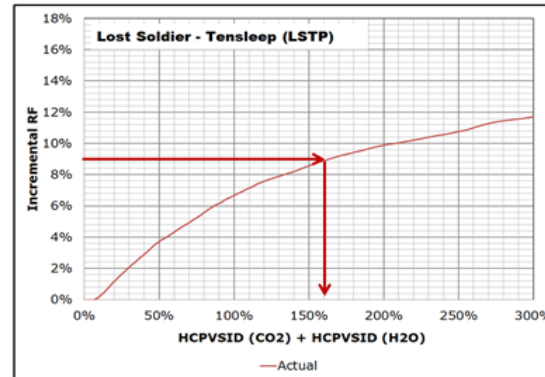
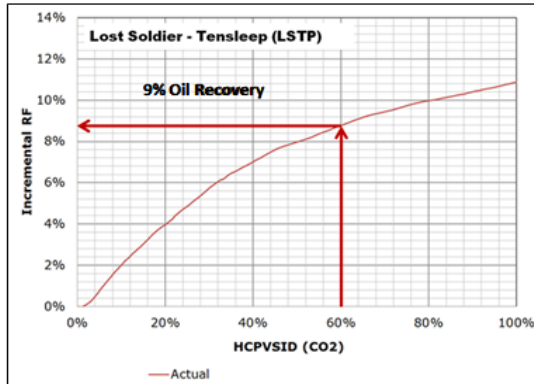
Bairoil Field – Lost Soldier and Wertz (Wyoming)



On the Outside they both look the same

Rocky Mountain Region

Lost Soldier Tertiary Oil Recovery Comparison at 60% HCPV Injected w/ Rangely field



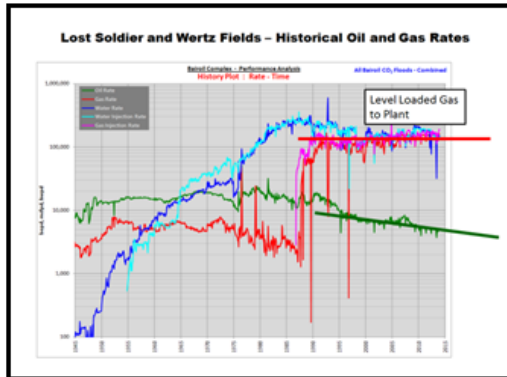
CO₂ Only

CO₂ + H₂O

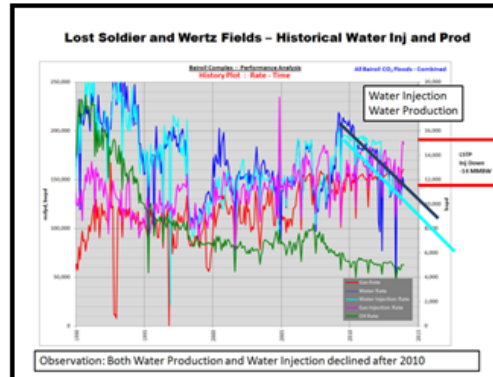
**On the Outside at 60% HCPV Injected
they both look the same about 9% OOIP**

2014

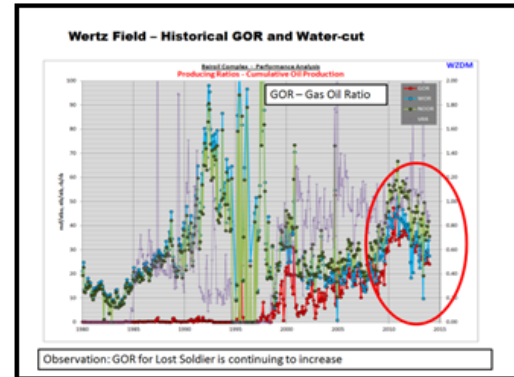
Lost Soldier and Wertz Field Analysis Field Level Analysis (Historical WAG Management)



At the Field Level, Historical Production Looks Normal – (Level Loaded at Plant)

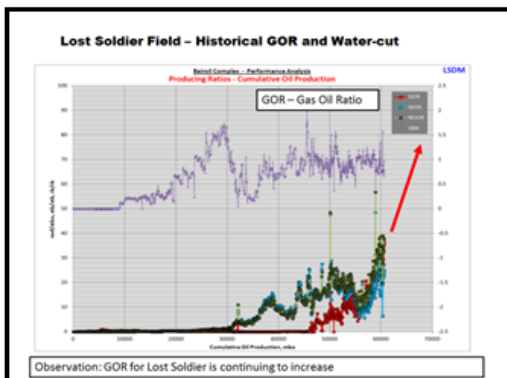


In 2010, WAG Management was changed resulting in 14 MMBW of WAG Water Injection going down the creek.

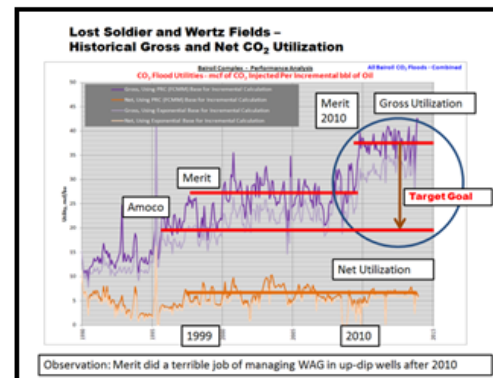


By implementing Rangely's WAG management in 2010, Gas Production increased dramatically.

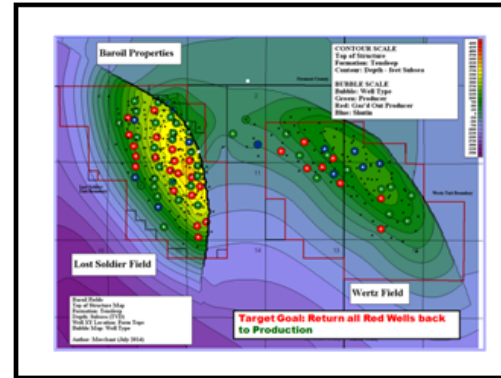
Montage Pattern Analysis – Mass Balance approach to Tertiary WAG Reservoir Management Optimization – Lost Soldier and Wertz fields



The GOR increase caused many of the wells in the field to gas out capable of producing only a few days a month.



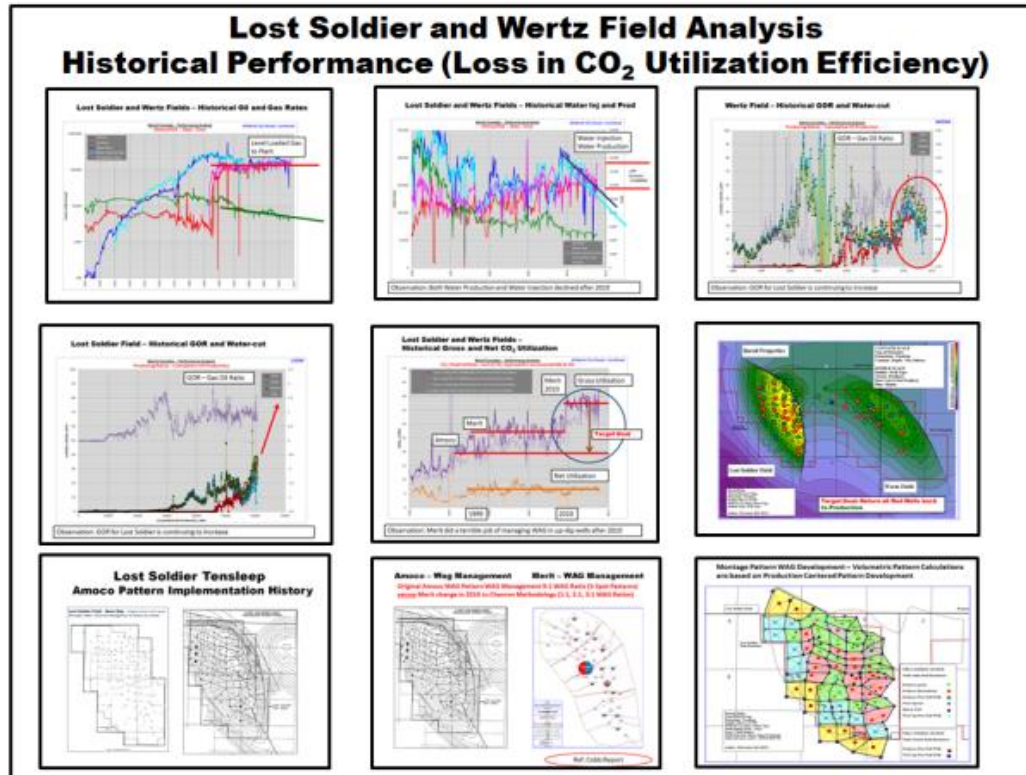
Gross Utilization efficiency went from 13 MSCF/BO (Amoco) to 40 MSCF/BO



The final result was 37% of the wells in the field are off production. If returned, over 3,000 BOPD could be added.

2014

Lost Soldier and Wertz Field Analysis (CO₂ Utilization – Tertiary Process Efficiency)



Merit Company in 2010 modified Amoco's five-spot pattern 9:1 WAG scheme to Rangely's 1:1, 2:1, and 3:1 WAG scheme by dividing the unit up into thirds. From 2010, Fourteen million barrels of water went down the creek that was suppose to be used for WAG Management. The result gassed out 37% of the wells in Lost Soldier field by lowering WAG efficiency from 13 MSCF/BO (Amoco) to over 40 MSCF/BO.

Fortunately, Bad WAG can be fixed...

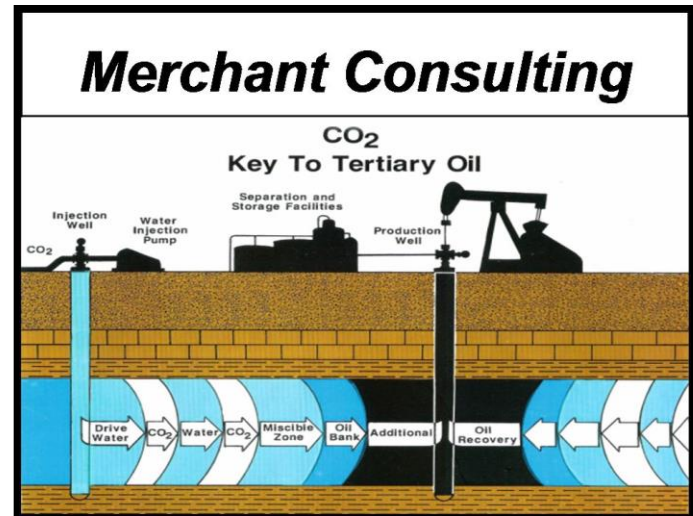
CMTC-502866-MS Enhanced Oil Recovery The History of CO₂ Conventional WAG Injection Techniques developed from Lab in the 1950's to 2017

Questions?

David H. Merchant



CO₂ Storage Solutions



Merchant Consulting

WEB Site: www.CO2StorageSolutions.com

Email: merchantconsulting@comcast.net

Presented to Houston CMTC Conference

**July 18, 2017
Houston, Texas**