Overview or CO_2 Injection – Performance Metrics and the Wellman Unit Case History

Dr. David S. Schechter

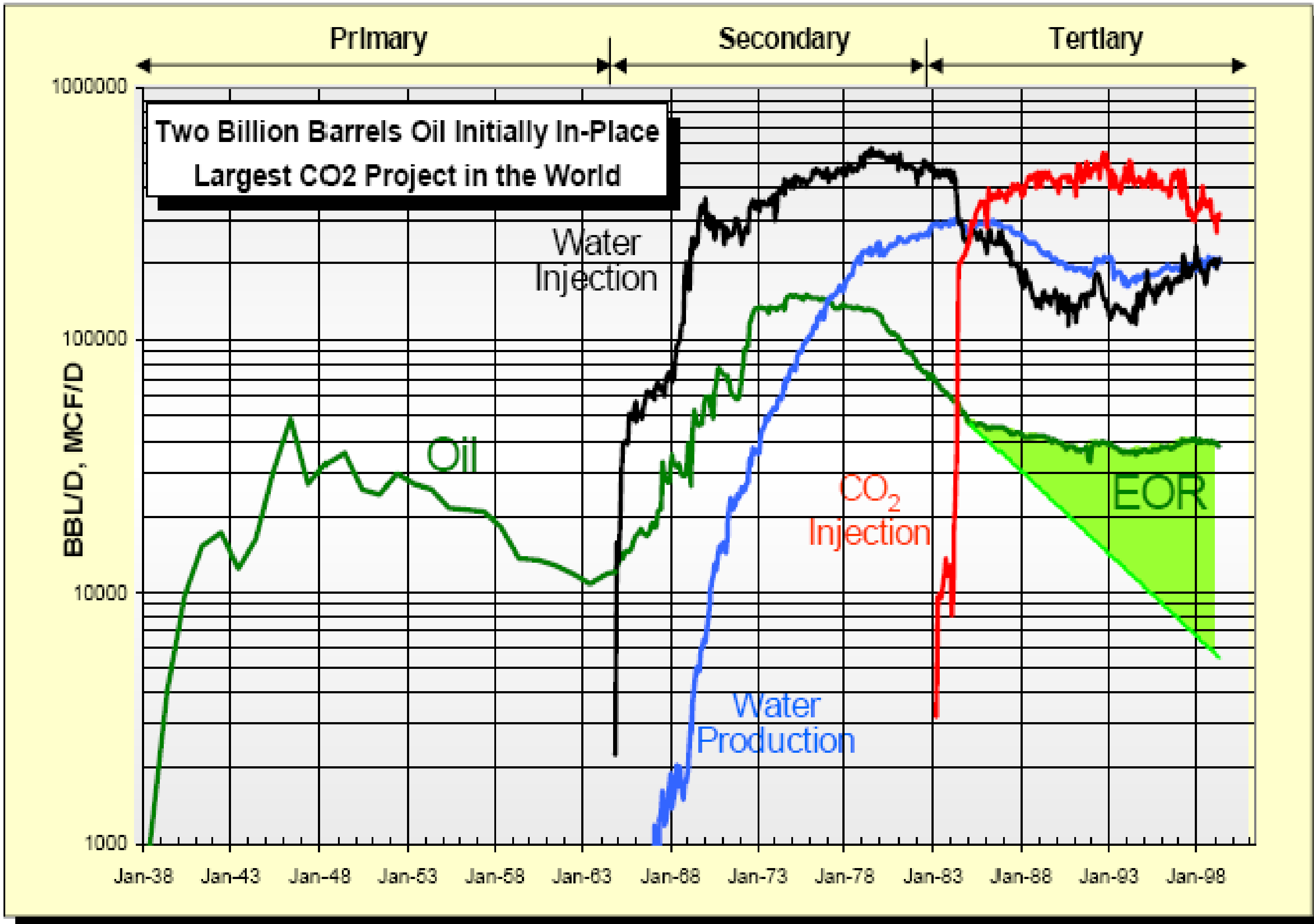
Texas A&M University

Important Metrics

Utilization = Mcf CO_2 per 1 Bbl EOR

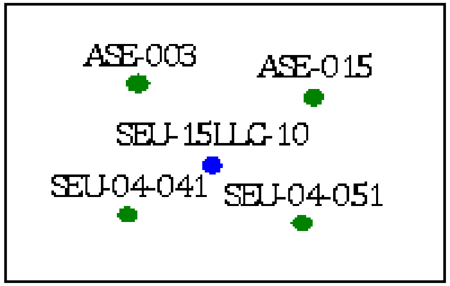
Recovery Factor vs. HCPV Injected

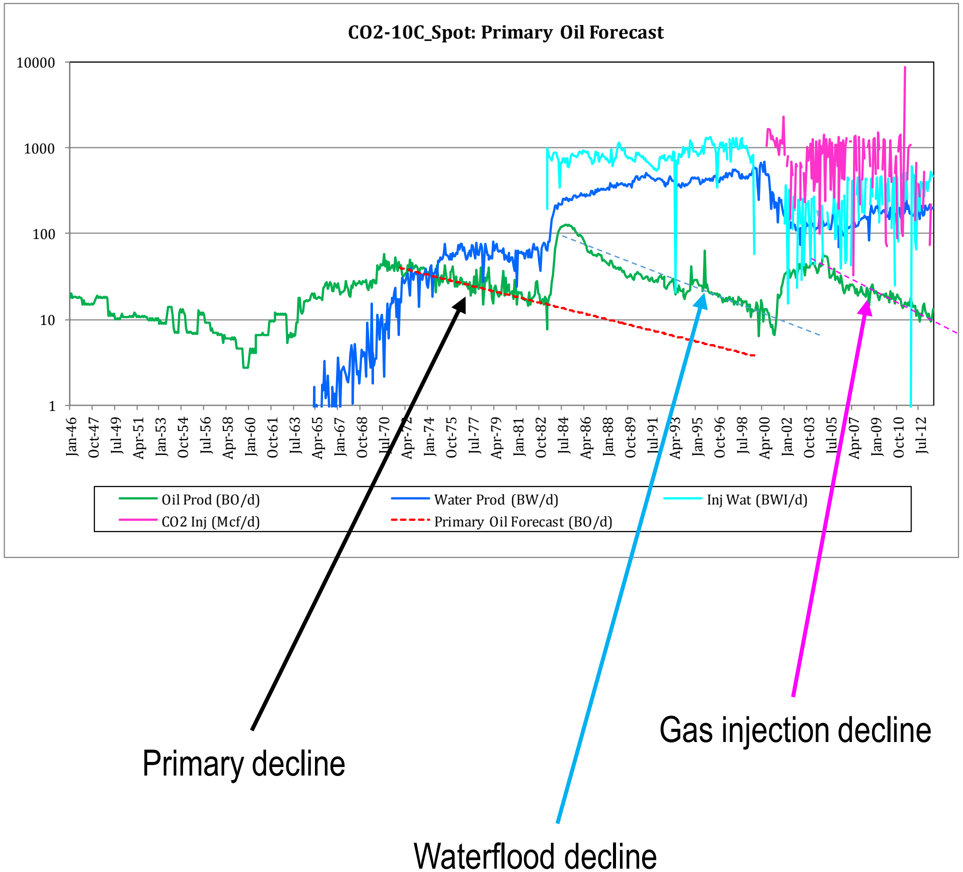
Denver Unit Production/Injection History

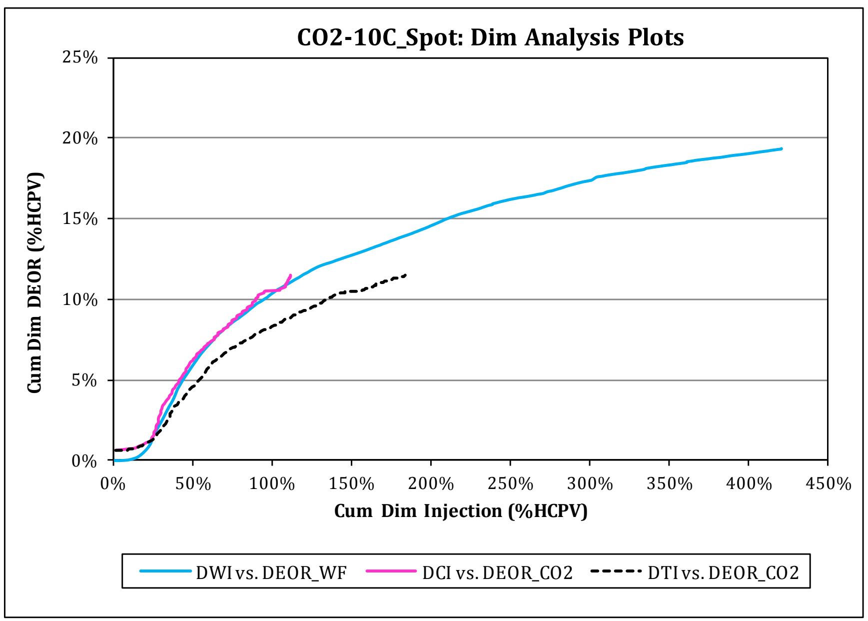


CO_2 EOR Primer NETL

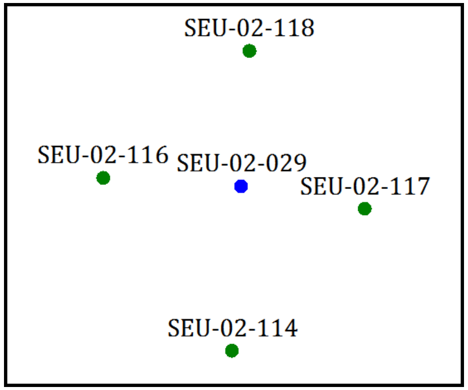
Rule of Thumb? – Good Waterflood ⟶ Good EOR Response

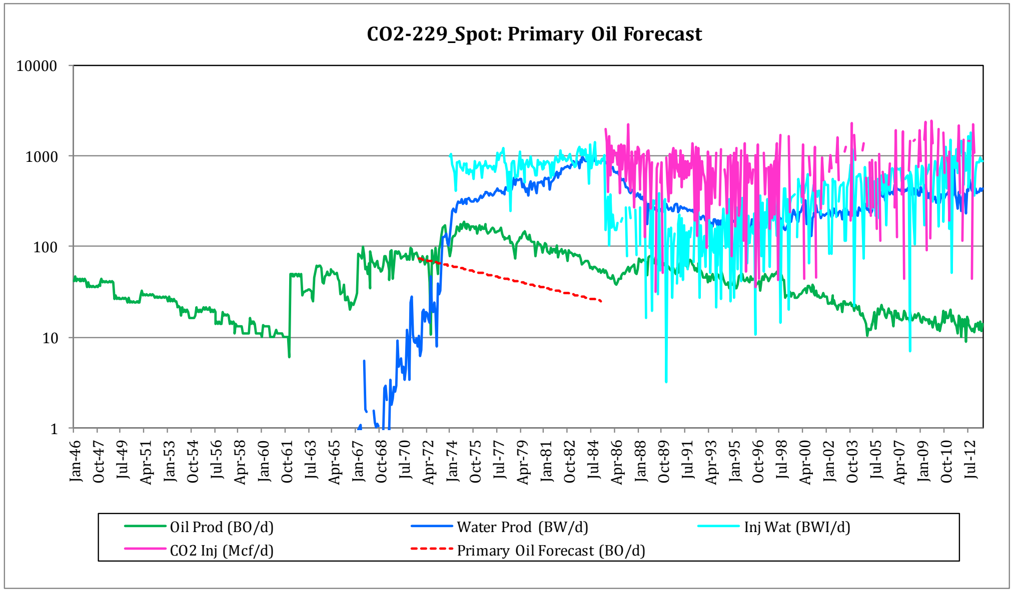


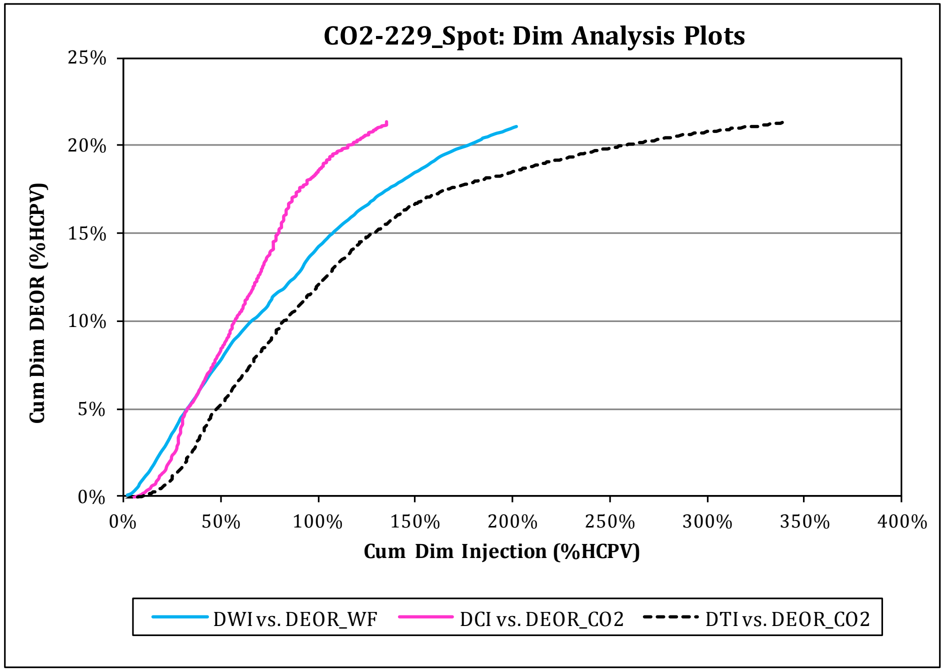




CO2-229_Spot

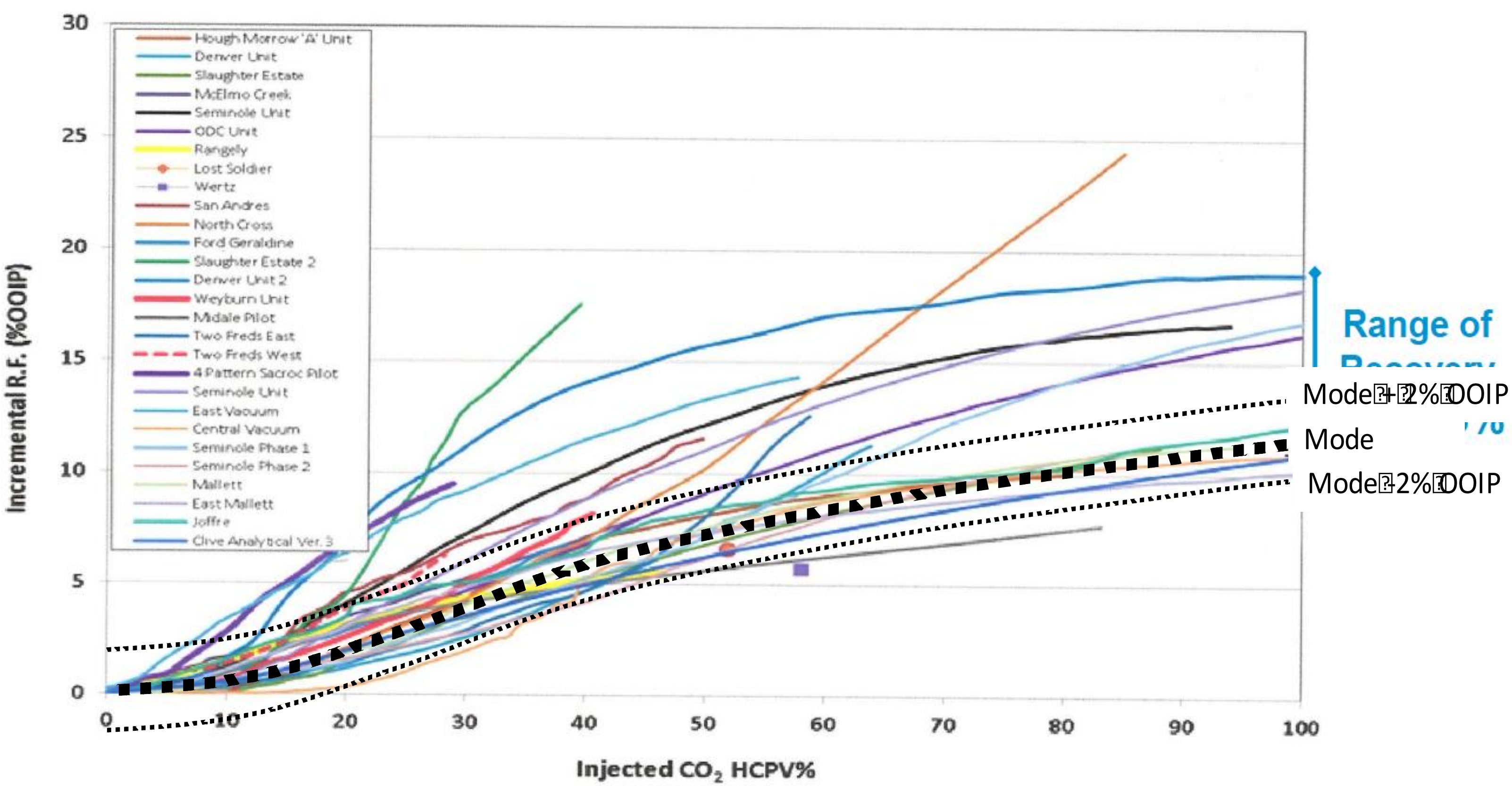

SEU-02-118
SEU-02-116
SEU-02-029
SEU-02-117
SEU-02-114


CO2-229_Spot: Primary Oil Forecast
10000
1000
100
10
1
Jan-46
Oct-47
Jul-49
Apr-51
Jan-53
Oct-54
Jul-56
Apr-58
Jan-60
Oct-61
Jul-63
Apr-65
Jan-67
Oct-68
Jul-70
Apr-72
Jan-74
Oct-75
Jul-77
Apr-79
Jan-81
Oct-82
Jul-84
Apr-86
Jan-88
Oct-89
Jul-91
Apr-93
Jan-95
Oct-96
Jul-98
Apr-00
Jan-02
Oct-03
Jul-05
Apr-07
Jan-09
Oct-10
Jul-12
Oil Prod (BO/d)
Water Prod (BW/d)
Inj Wat (BWI/d)
CO2 Inj (Mcf/d)
Primary Oil Forecast (BO/d)

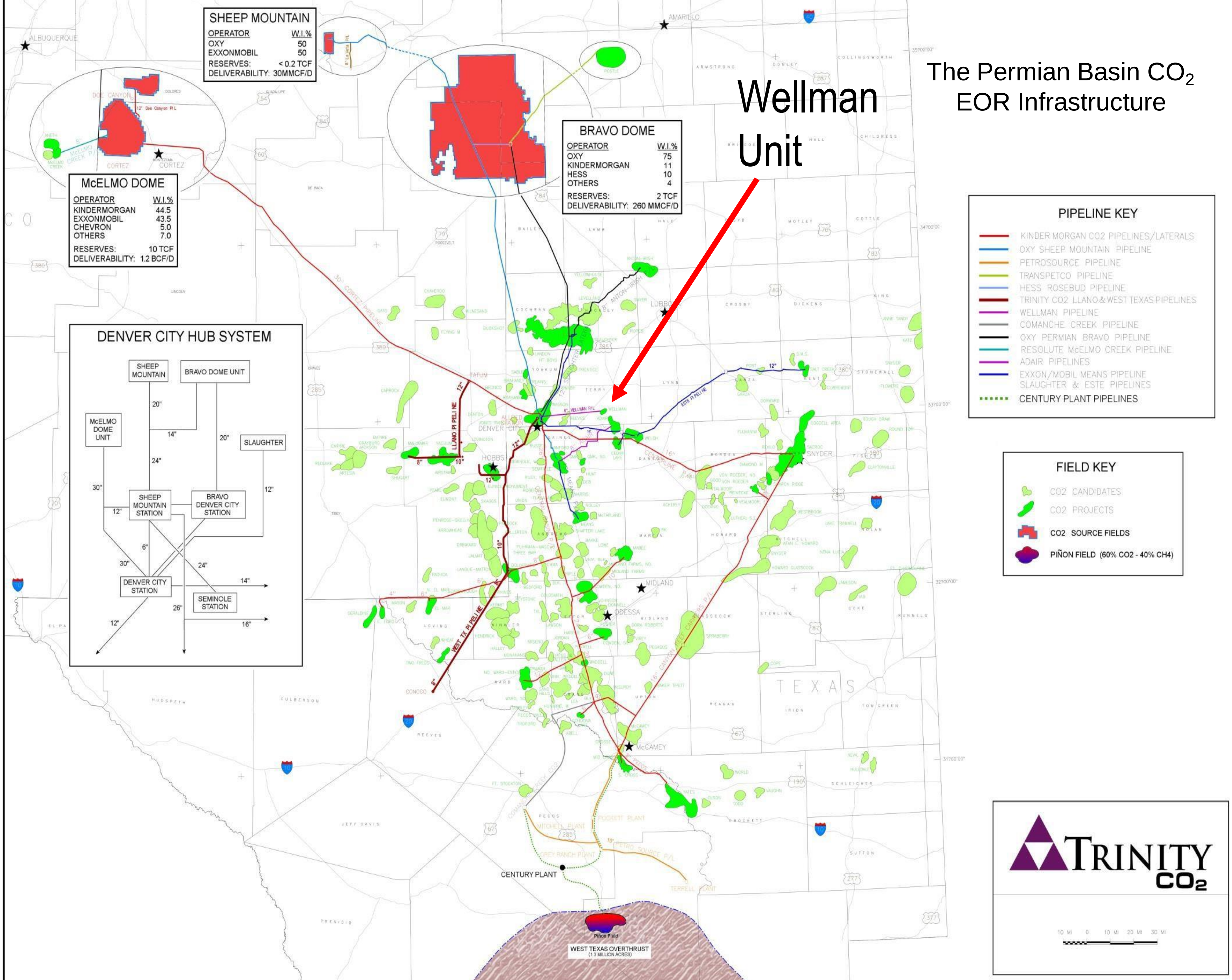

CO2-229_Spot: Dim Analysis Plots
25%
20%
15%
10%
5%
0%
Cum Dim DEOR (%HCPV)
0%
50%
100%
150%
200%
250%
300%
350%
400%
Cum Dim Injection (%HCPV)
DWI vs. DEOR_WF
DCI vs. DEOR_CO2
DTI vs. DEOR_CO2

Metrics of Several Floods

			feet	F	%	md	feet	API	cp	%HCPV	%OOIP	MCF/STB	MCF/STB	-
Field Scale Projects														
Dollarhide	TX	Trip. Chert	7,800	120	17.0	9	48	40	0.4	30	14.0		2.4	1985
East Vacuum	NM	Ooliti dolomite	4,400	101	11.7	11	71	38	1.0	30	8.0	11.1	6.3	1985
Ford Geraldine	TX	Sandstone	2,680	83	23.0	64	23	40	1.4	30	17.0	9.0	5.0	1981
Means	TX	Dolomite	4,400	100	9.0	20	54	29	6.0	55	7.1	15.2	11.0	1983
North Cross	TX	Trip. Chert	5,400	106	22.0	5	60	44	0.4	40	22.0	18.0	7.8	1972
Northeast Purdy	OK	Sandstone	8,200	148	13.0	44	40	35	1.5	30	7.5	6.5	4.6	1982
Rangely	CO	Sandstone	6,500	160	15.0	5 to 50	110	32	1.6	30	7.5	9.2	5.0	1986
SACROC (17 pattern)	TX	Carbonate	6,400	130	9.4	3	139	41	0.4	30	7.5	9.7	6.5	1972
SACROC (14 pattern)	TX	Carbonate	6,400	130	9.4	3	139	41	0.4	30	9.8	9.5	3.2	1981
South Welch	TX	Dolomite	4,850	92	12.8	13.9	132	34	2.3	25	7.6			
Twofreds	TX	Sandstone	4,820	104	20.3	33.4	18	36	1.4	40	15.6	15.6	8.0	1974
Wertz	WY	Sandstone	6,200	165	10.7	16	185	35	1.3	60	10.0	13.0	10.0	1986
Producing Pilots														
Garber	OK	Sandstone	1,950	95	17.0	57	21	47	2.1	35	14.0		6.0	1981
Little Creek	MS	Sandstone	10,400	248	23.4	75	30	39	0.4	160	21.0	27.0	12.6	1975
Majamar	NM	Anhydritic dolomite	4,050	90	10.0	11.2	49	36	0.8	30	8.2	11.6	10.7	1983
Majamar	NM	Dolomitic sandstone	3,700	90	11.0	13.9	23	36	0.8	30	17.7	8.1	6.1	1983
North Coles Levee	CA	Sandstone	9,200	235	15.0	9	136	36	0.5	63	15.0	7.4		1981
Quarantine Bay	LA	Sandstone	8,180	183	26.4	230	15	32	0.9	19	20.0		2.4	1981
Slaughter Estate	TX	Dolomitic sandstone	4985	105	12.0	8	75	32	2.0	26	20.0	16.7	3.7	1976
Weeks Island	LA	Sandstone	13,000	225	26.0	1200	186	33	0.3	24	8.7	7.9	3.3	1978
West Sussex	WY	Sandstone	3,000	104	19.5	28.5	22	39	1.4	30	12.9	8.9		1982
											Field Projects ==>	11.7	6.3	Average
												10.4	6.3	Median
											Pilot Projects ==>	12.6	6.4	Average
												8.9	6.0	Median



- An auditor's view, Mike Stell, Ryder Scott, Permian Basin Study Group, April 4, 2011
- Reserve booking guidelines, Mike Stell, Ryder Scott, CO2 Conference, Midland December 8, 2005
- What is important in the reservoir, Richard Baker, Appega Conference, April 22, 2004



The Permian Basin CO_2 EOR Infrastructure
Wellman Unit
SHEEP MOUNTAIN
OPERATOR W.I.%
OXY 50
EXXONMOBIL 50
RESERVES: < 0.2 TCF
DELIVERABILITY: 30MMCF/D
BRAVO DOME
OPERATOR W.I.%
OXY 75
KINDERMORGAN 11
HESS 10
OTHERS 4
RESERVES: 2 TCF
DELIVERABILITY: 260 MMCF/D
McELMO DOME
OPERATOR W.I.%
KINDERMORGAN 44.5
EXXONMOBIL 43.5
CHEVRON 5.0
OTHERS 7.0
RESERVES: 10 TCF
DELIVERABILITY: 1.2 BCF/D
DENVER CITY HUB SYSTEM
SHEEP MOUNTAIN
BRAVO DOME UNIT
McELMO DOME UNIT
SLAUGHTER
SHEEP MOUNTAIN STATION
BRAVO DENVER CITY STATION
DENVER CITY STATION
SEMINOLE STATION
PIPELINE KEY
KINDER MORGAN CO2 PIPELINES/LATERALS
OXY SHEEP MOUNTAIN PIPELINE
PETROSOURCE PIPELINE
TRANSPETCO PIPELINE
HESS ROSEBUD PIPELINE
TRINITY CO2 LLANO & WEST TEXAS PIPELINES
WELLMAN PIPELINE
COMANCHE CREEK PIPELINE
OXY PERMIAN BRAVO PIPELINE
RESOLUTE McELMO CREEK PIPELINE
ADAIR PIPELINES
EXXON/MOBIL MEANS PIPELINE SLAUGHTER & ESTE PIPELINES
CENTURY PLANT PIPELINES
FIELD KEY
CO2 CANDIDATES
CO2 PROJECTS
CO2 SOURCE FIELDS
PIÑON FIELD (60% CO2 - 40% CH4)
ALBUQUERQUE
AMARILLO
LUBBOCK
DENVER CITY
HOBBS
SNYDER
MIDLAND
ODESSA
McCAMEY
CORTEZ
CENTURY PLANT
WEST TEXAS OVERTHRUST
LLANO PIPELINE
WEST TX PIPELINE
TEXAS
TRINITY CO2

Case History Wellman Unit

Wellman Unit Phase 1
Laboratory Evaluation of Injection in the Transition Zone

OUTLINE

- Introduction
- Laboratory Evaluation
- Field Performance

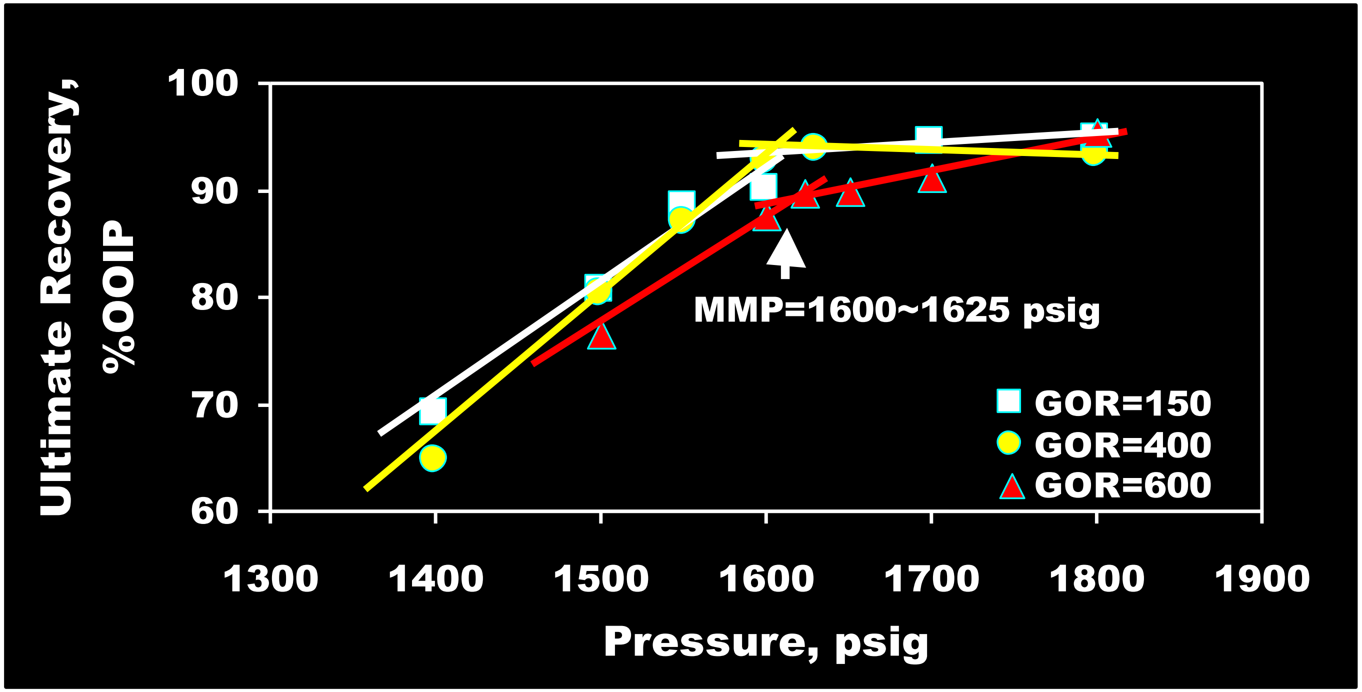
CO_2 Recovery Mechanism (Gravity Drainage)

- To examine the performance of recovery at or near the MMP with CO_2 in:
  - standard slim tube
  - vertically-oriented, bead-packed large diameter tubes
  - vertically-oriented reservoir cores at reservoir conditions
- To examine possibility that residual oil exists below the original water-oil contact that could be mobilized by continuation of CO_2 injection

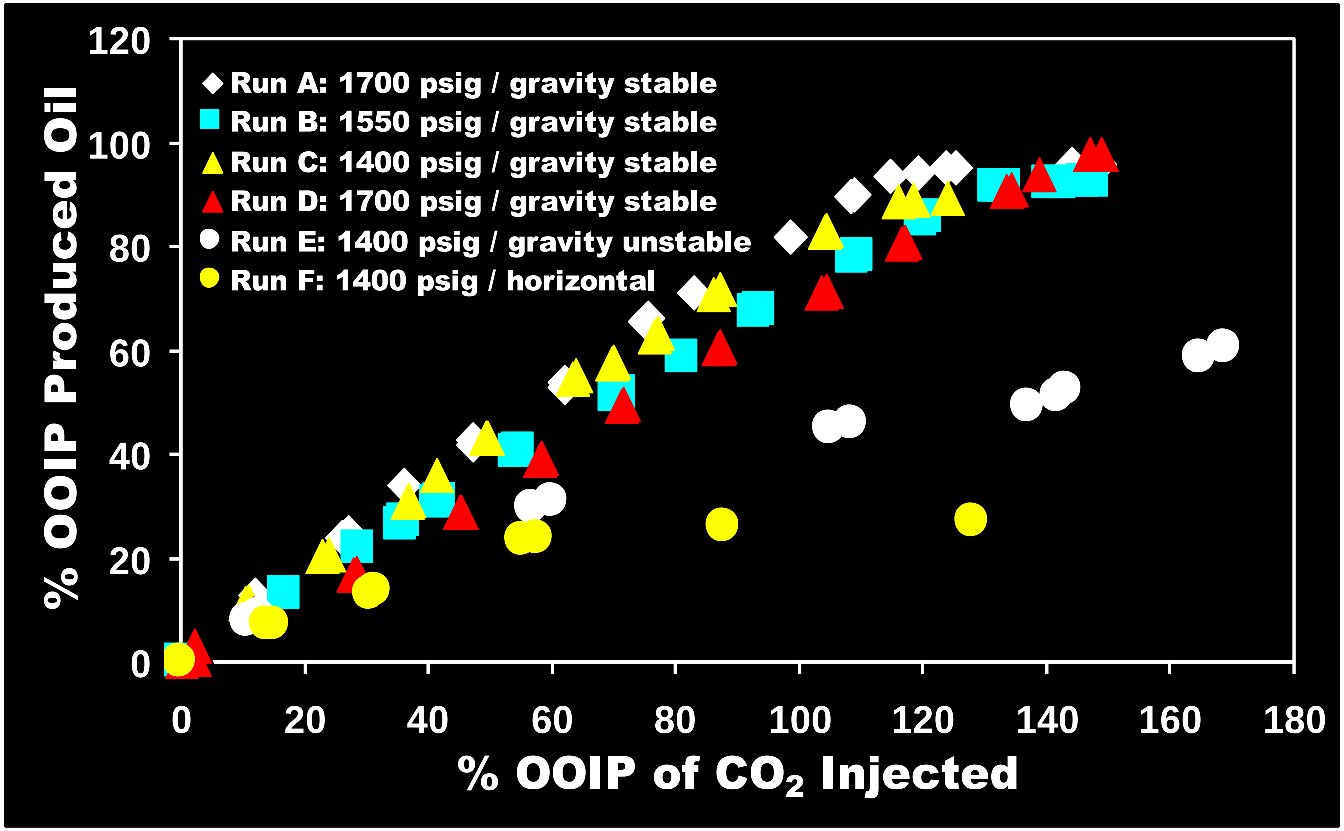
Wellman Unit Oil Characteristics

- separator oil taken at 61 ^{o}F and 126 psig
- average molecular weight: 147 g/mol
- GOR: 150 scf/bbl
- density: 0.8329 g/cm^3 @ 100 ^{o}F and 1000 psig
- viscosity: 2.956 cp

Recovery vs. Pressure for Different GOR's in Slim Tube



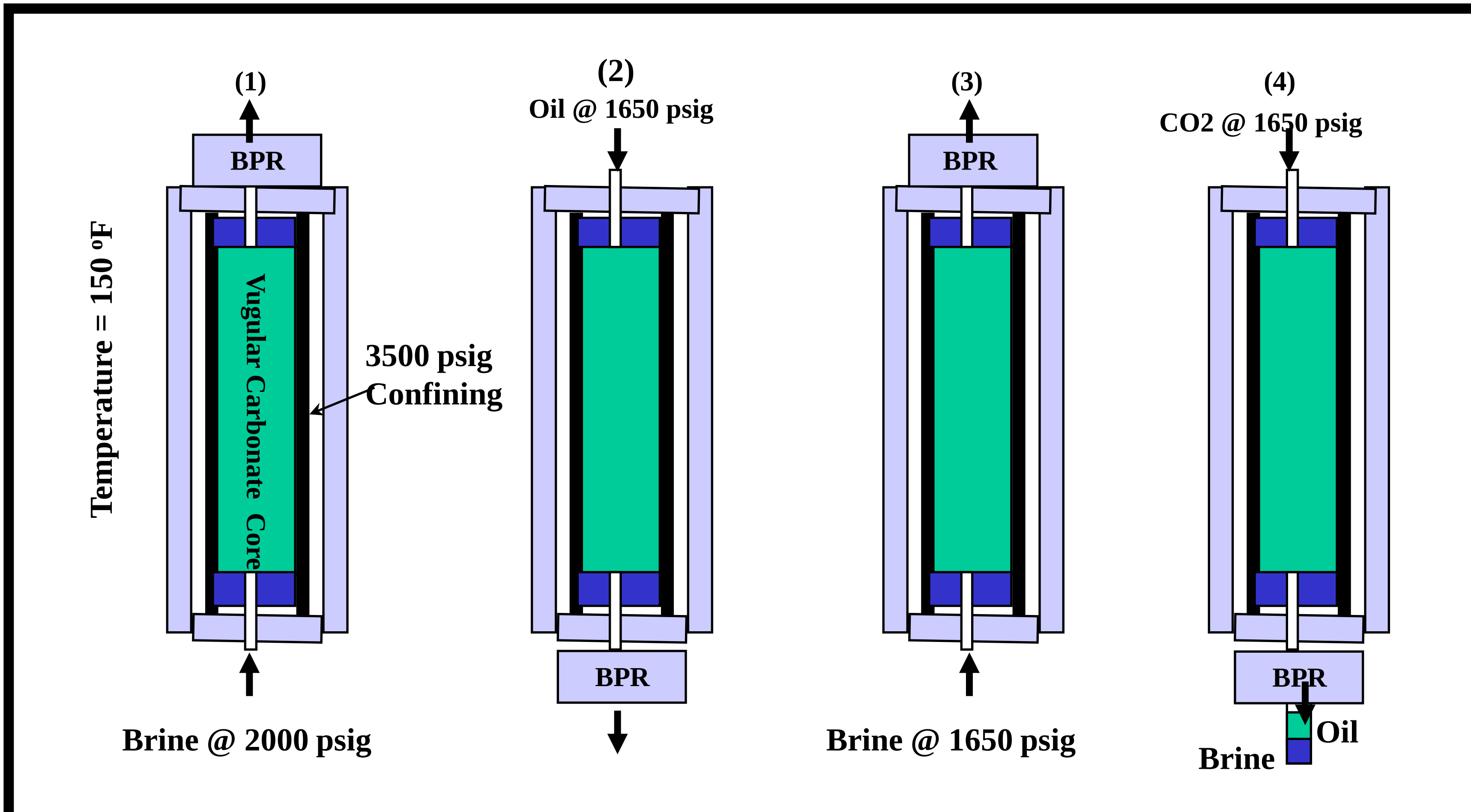
Recovery Curves for Each Large Diameter Tube Test



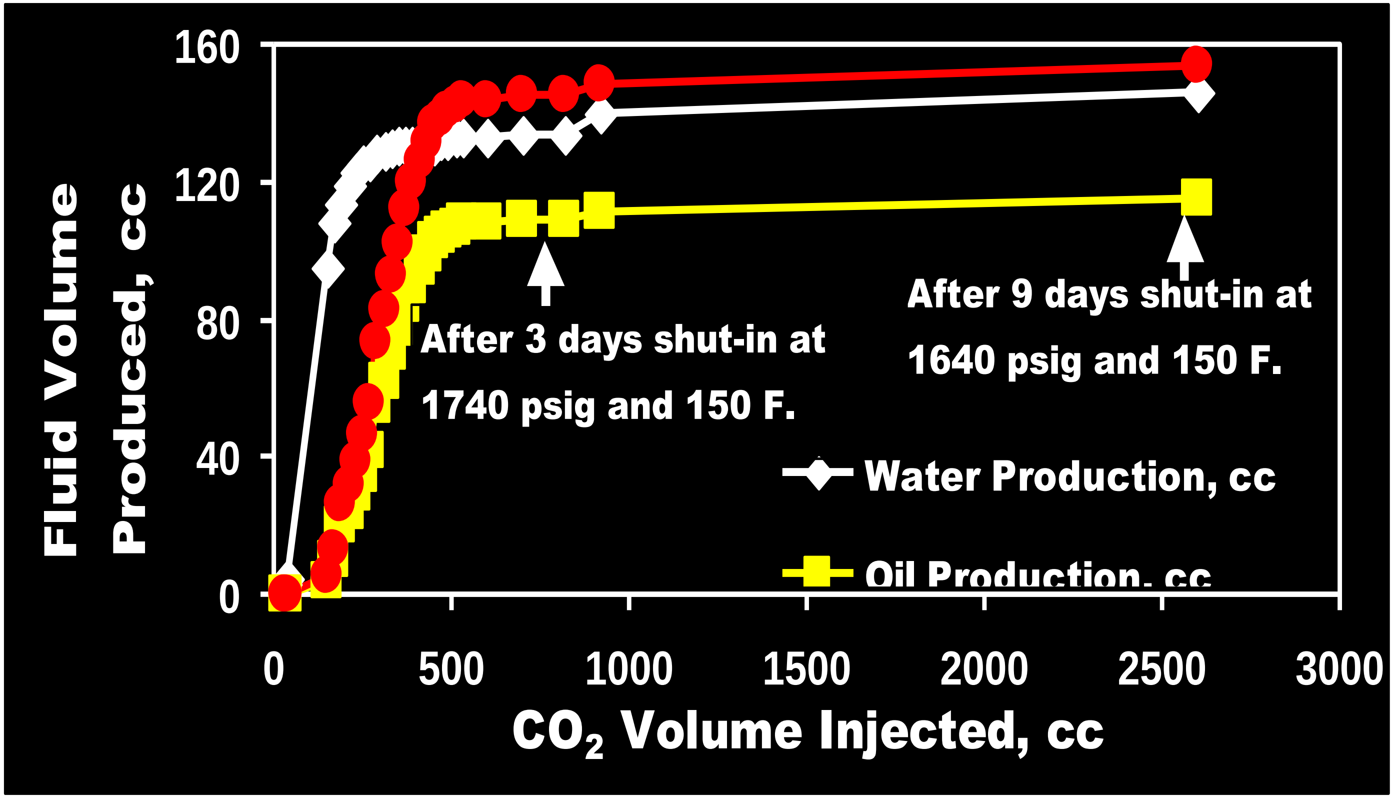
Cores From Wellman 5-10

- 30’ whole core from 9400’ to 9430’
- 26 samples for standard core analysis
- 3’ section for gravity stable CO_2 tests
- helium porosities: 2.4% ~ 12.6%
- average porosity: 5.8% for 26 samples
- average water saturation: 42%

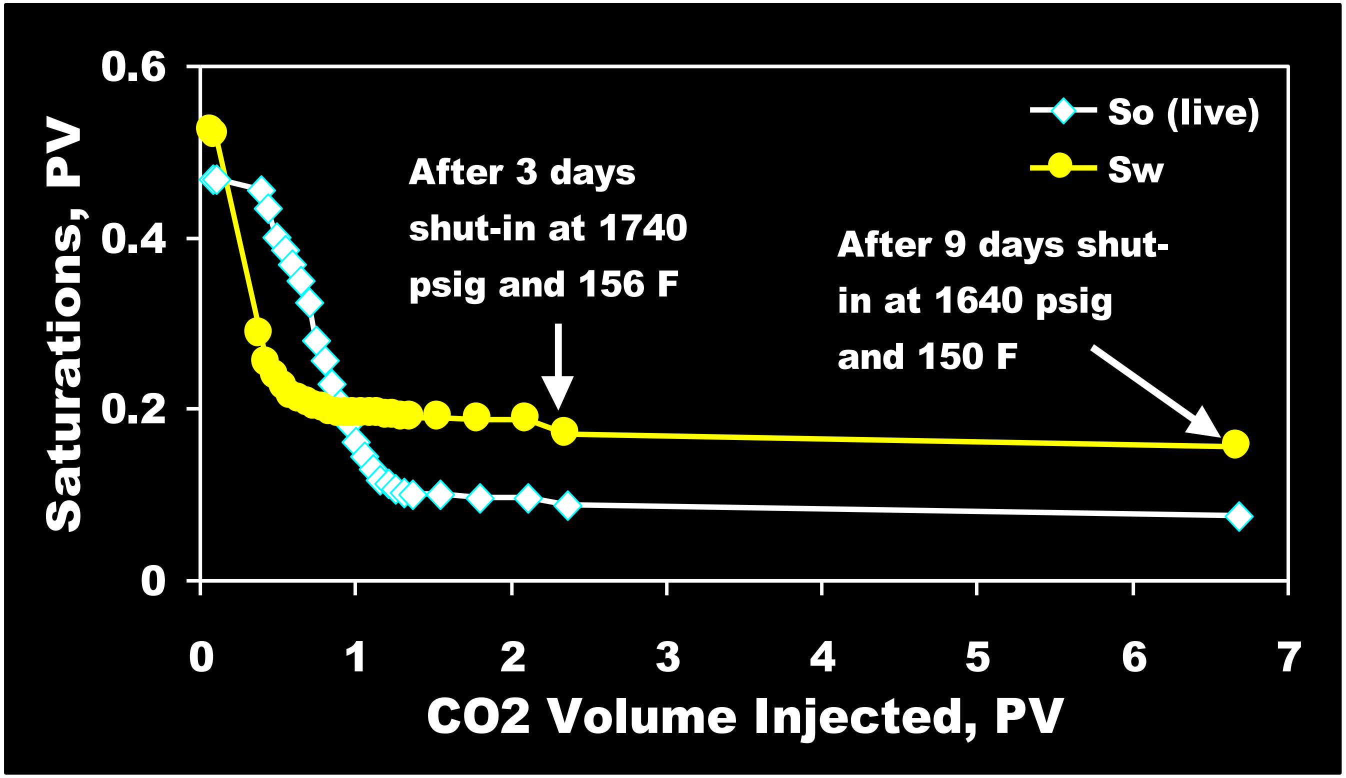
A Schematic Diagram of the Core Holder and Procedure



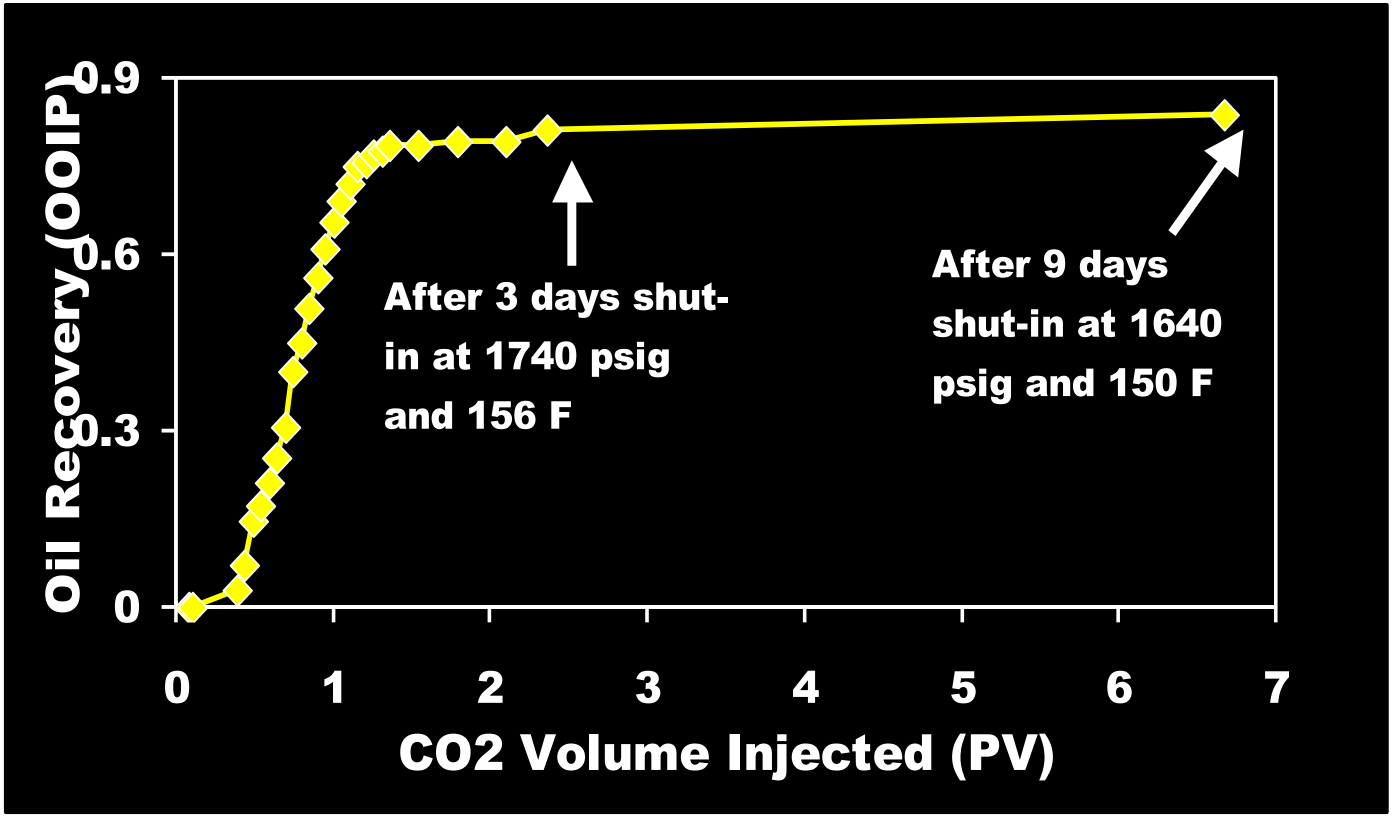
Fluid Production vs. CO_2 Throughput During CO_2-Assisted Gravity Drainage at a Pressure of 1650 psig



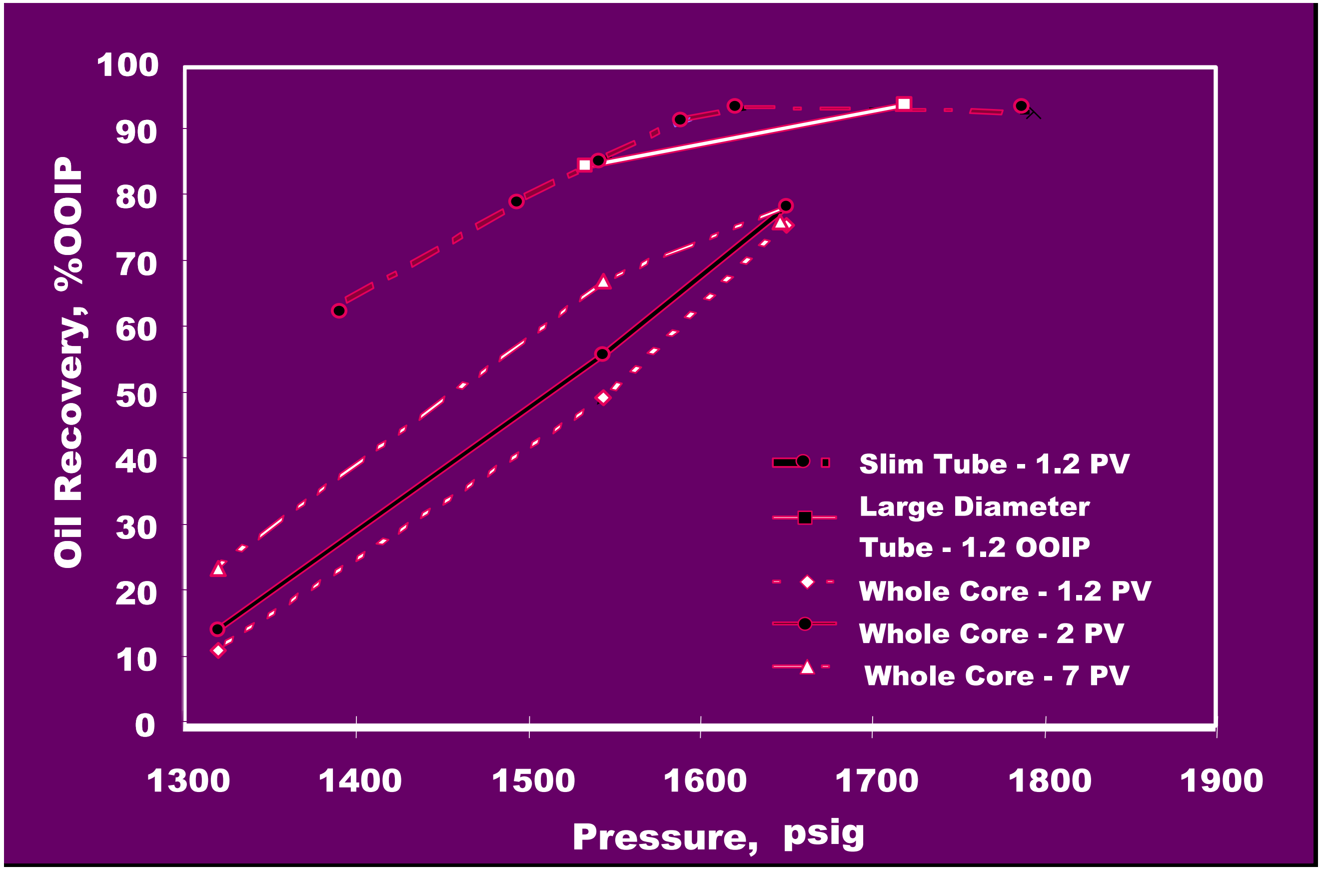
Changes in Fluid Saturations in the Wellman Unit Whole Core During CO_2-Assisted Gravity Drainage



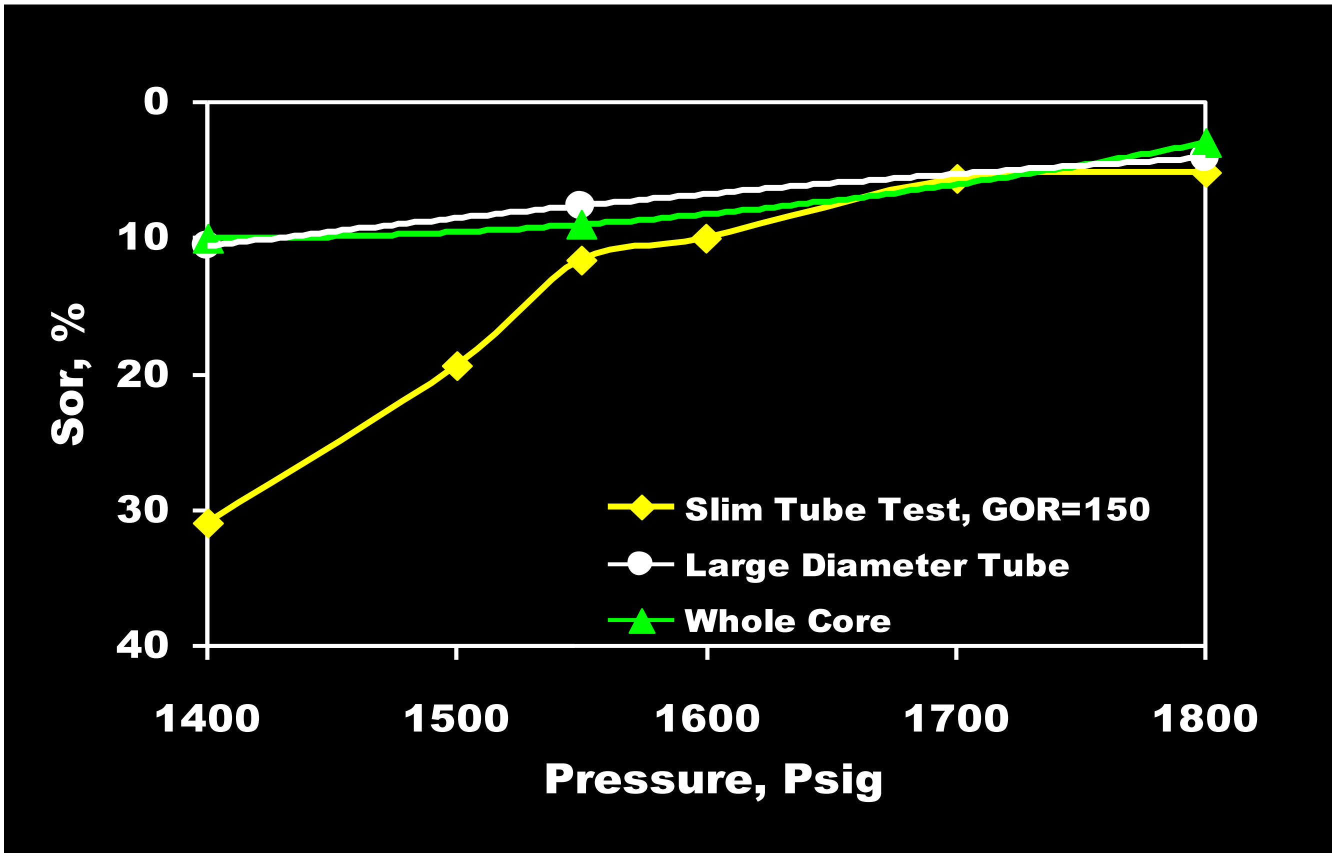
Oil Recovery From the Wellman Unit Whole Core During CO_2-Assisted Gravity Drainage



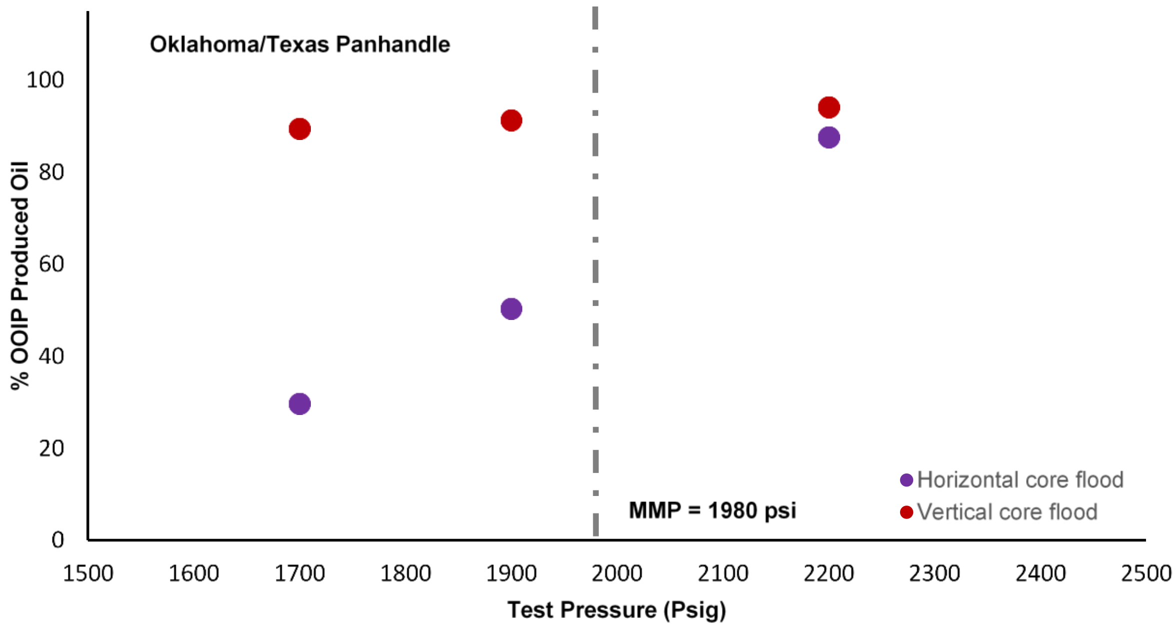
Oil Recovery From the Wellman Unit Whole Core During CO_2-Assisted Gravity Drainage at a Pressure of 1650 psig



S_{or} From the Wellman Unit Whole Core During CO_2-assisted Gravity Drainage at Three Pressures Above and Below the MMP



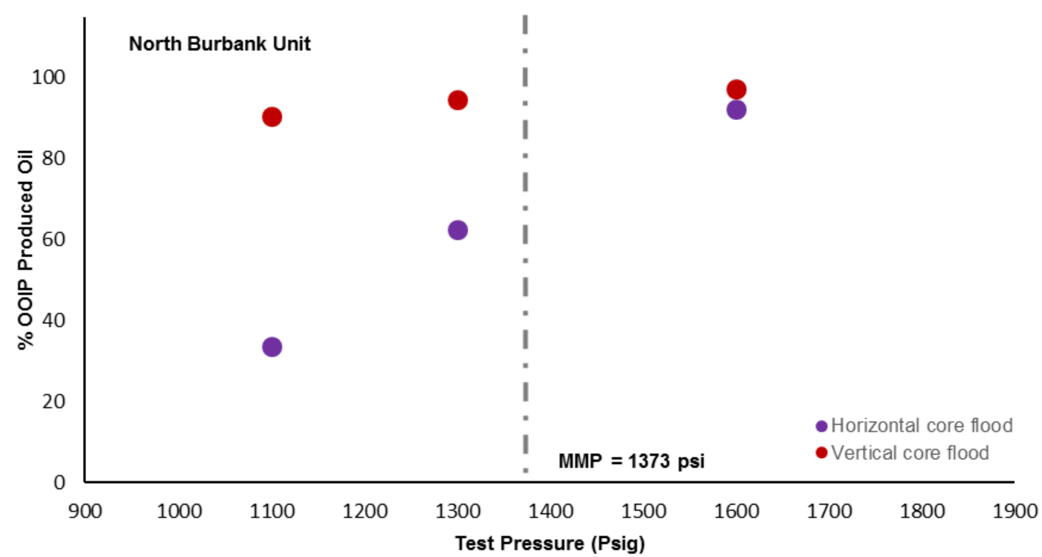
Gravity Stable Outperforms Slim Tube!



SPE-190183-MS

2018 SPE IOR

The Impact of Gas-Assisted Gravity Drainage on Operating Pressure in a Miscible CO_2 Flood

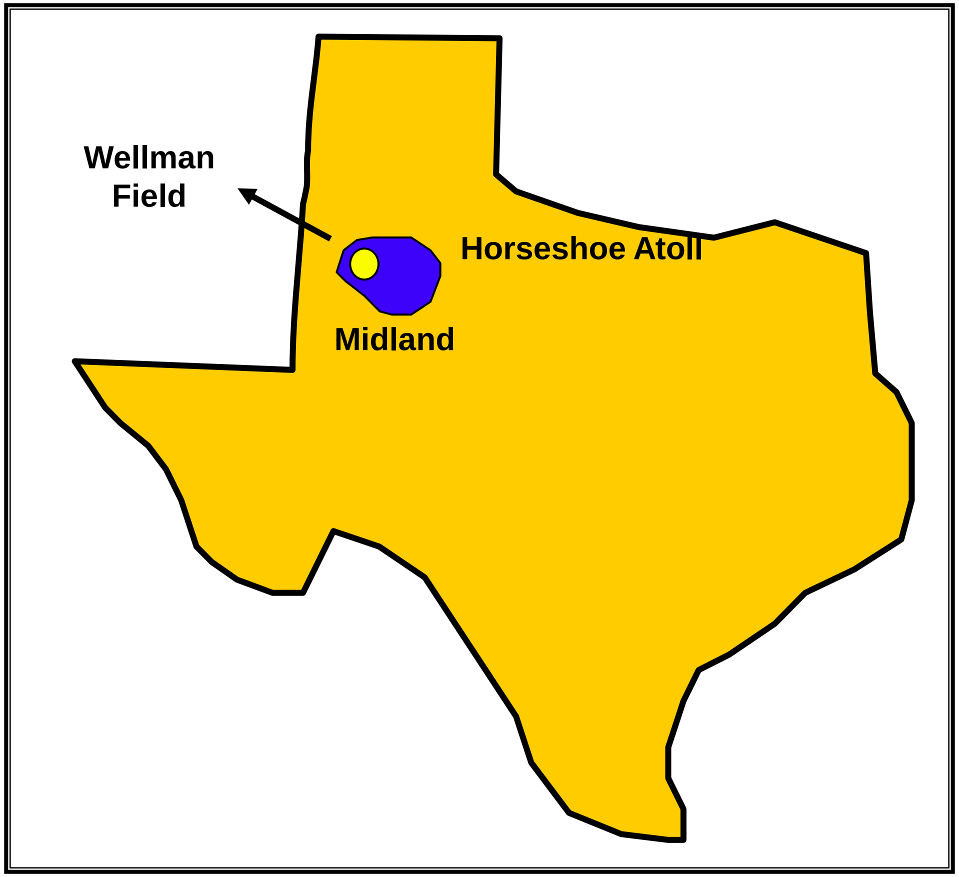


Case History Wellman Unit

Wellman Unit Phase 2 Reservoir Performance of Injection in the Transition Zone

LOCATION

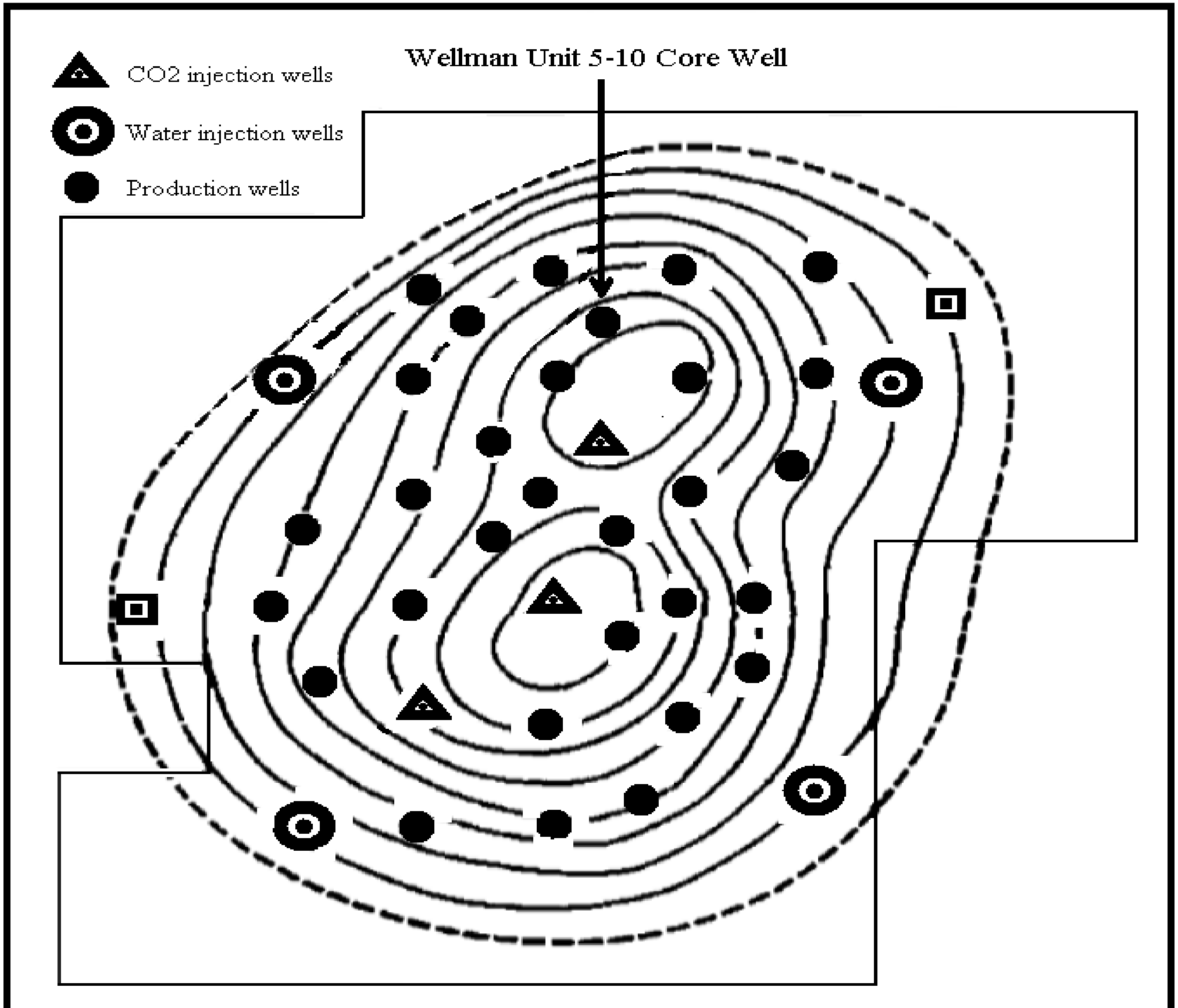
- Terry county, TX, along the Horseshoe Atoll reef complex that developed in North Midland during Pennsylvanian and early Permian time



INTRODUCTION

- History of the Wellman Unit CO_2 flood
- Two possibilities to optimize reservoir performance
  - Reducing CO_2 injection pressure to near the MMP
  - Mobilizing reserves in the water-oil transition zone below the original water-oil contact

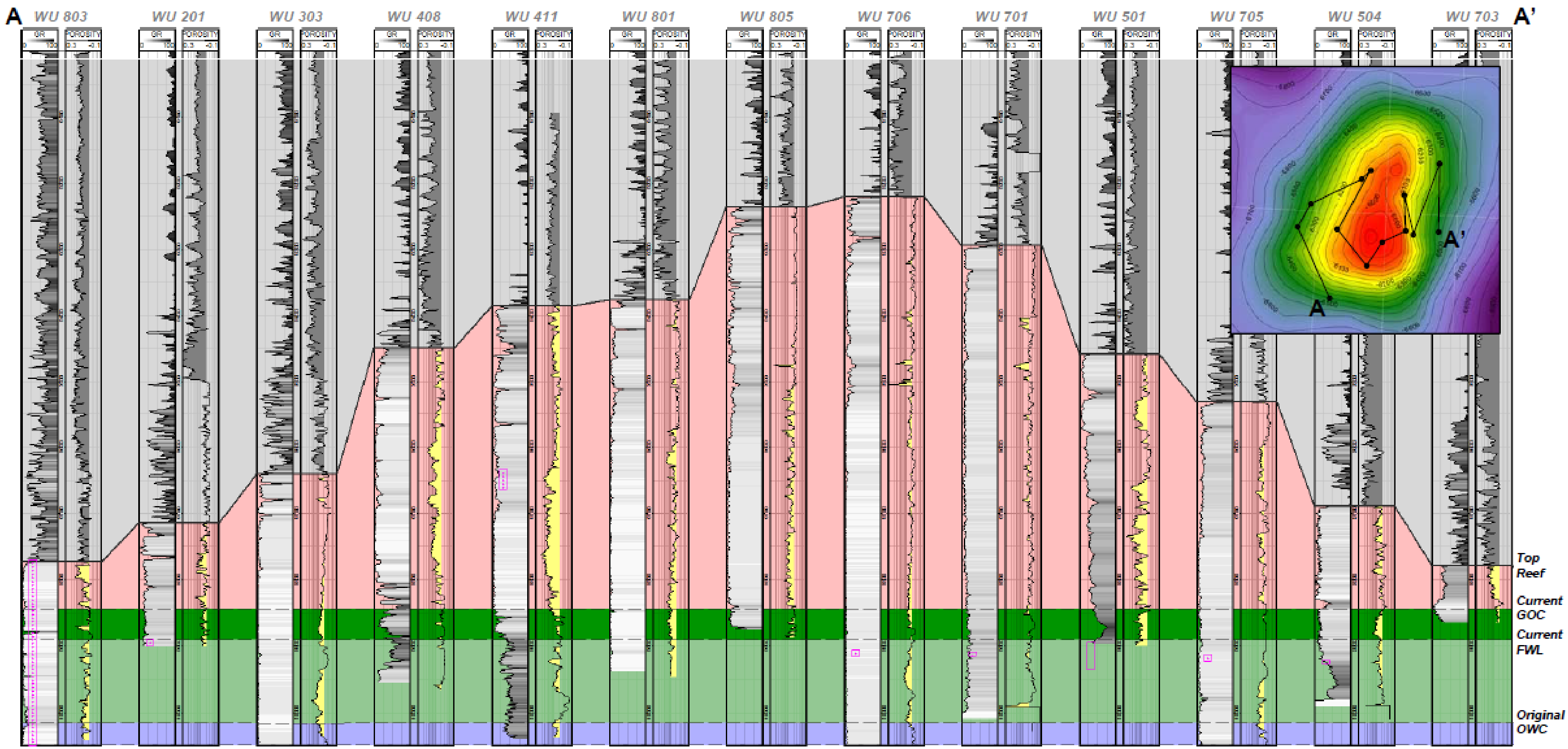
Wellman Unit Structure Map



Wellman Unit: Cross-Section Illustrates the Structure of the Pinnacle Reef

Variability but high quality reservoir at any oil column depth

Amount of CO_2 Sequestered in Gas Cap– 130 Bcf



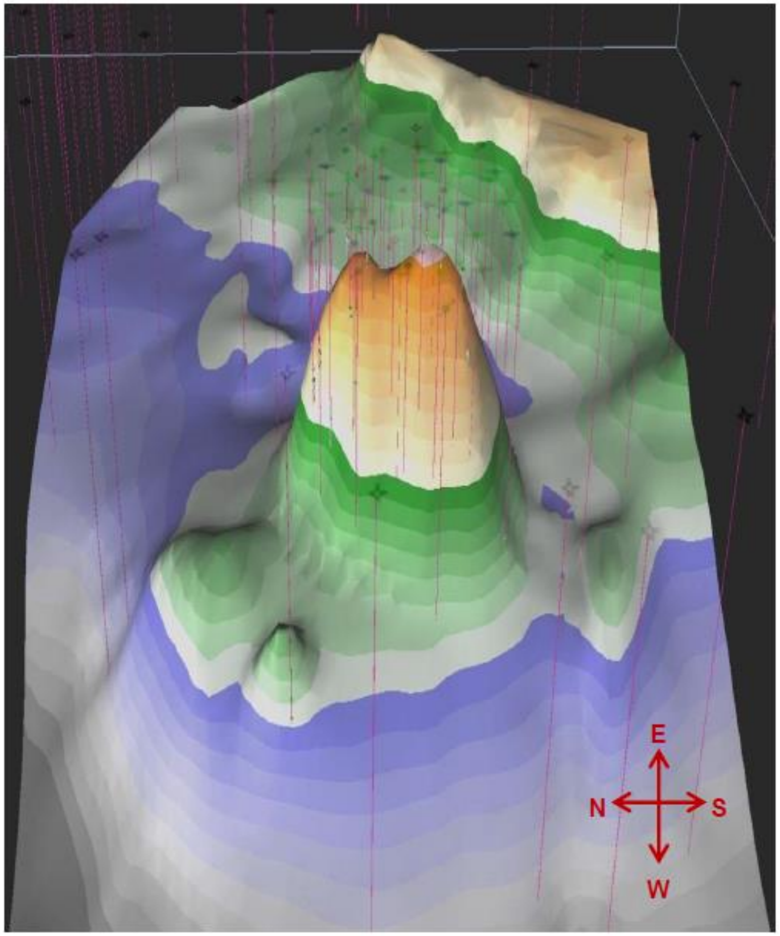
2,100 acres = 3.3 mi^2 = 8.5 km^2

Overview

- Pinnacle Reef structure of 2,100 acres
- Wolfcamp / Cisco formation at a depth of approximately 9,200 - 10,000 ft
- Extensive exposure and erosion
- Vugular porosity is a large part of the storage and delivery system
- Evidence of widespread fracturing
- Fracture porosity is a small part of the storage but a large part of the delivery system
- Some sections of intercrystalline porosity
  - Intercrystalline porosity is a small part of the storage and delivery system
- Two main pinnacles with vertical relief of over 800 ft
- Limited active Permian / Pennsylvanian water drive

Reservoir Properties	
OOIP	126 MMbbl
Original Oil-Water Contact ("OWC")	10,016 ft TVD
Oil Column Thickness	865 ft
Average Porosity	8 to 9%
Initial Sw	20%
Residual So	35%
Average Permeability	135 mD
Initial Reservoir Pressure	4,105 psi
Reservoir Temperature	151°F
Initial Oil Gravity	43.5°API
Bo	1.3
Oil Viscosity	0.43 cp

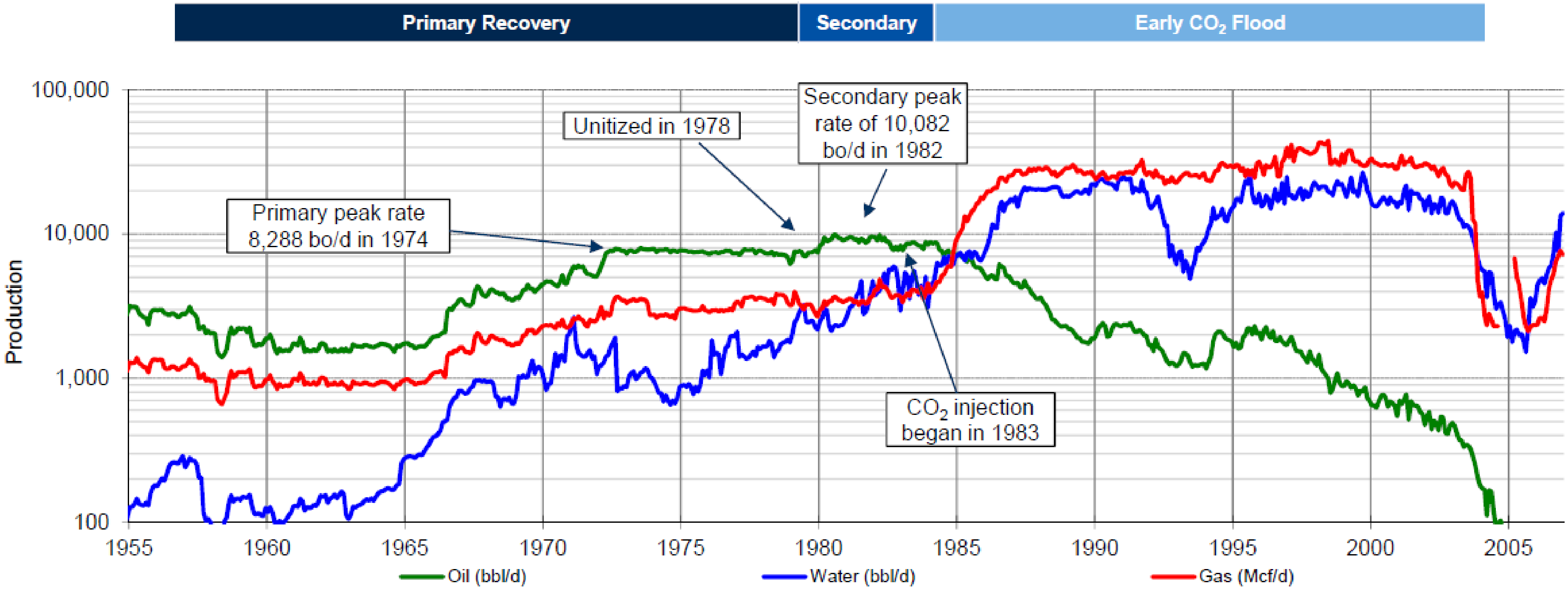
3-D Geological Model



Wellman Unit: Early Production History

Great primary and secondary performance but initial CO_2 flood implementation had limited success

Primary Recovery (1950 to 1979)	Secondary (1979 to 1983)	Early CO_2 Flood (1983 to 2003)
▪ Peak production 8,288 bo/d in 1974 ▪ Initial reservoir pressure 4,105 psi but dropped below the 1,250 psi bubble point by 1976 ▪ Field under allowable in early 1970s ▪ Discovery well IP'd over 2,100 boe/d ▪ **Recovery ~34% of OOIP**	▪ Make-up water injection initiated in 1979 with four wells below the OWC ▪ Peak production of 10,082 bo/d in 1982 ▪ Waterflood activities were cut short by implementation of CO_2 activities ▪ **Incremental recovery 10% of OOIP (10% total RF)**	▪ Union Texas began CO_2 injection in 1983 ▪ Initial CO_2 flood performance was modest and hampered by low commodity prices and poor flood maintenance ▪ Flood was eventually discontinued in 2003 due to poor economics

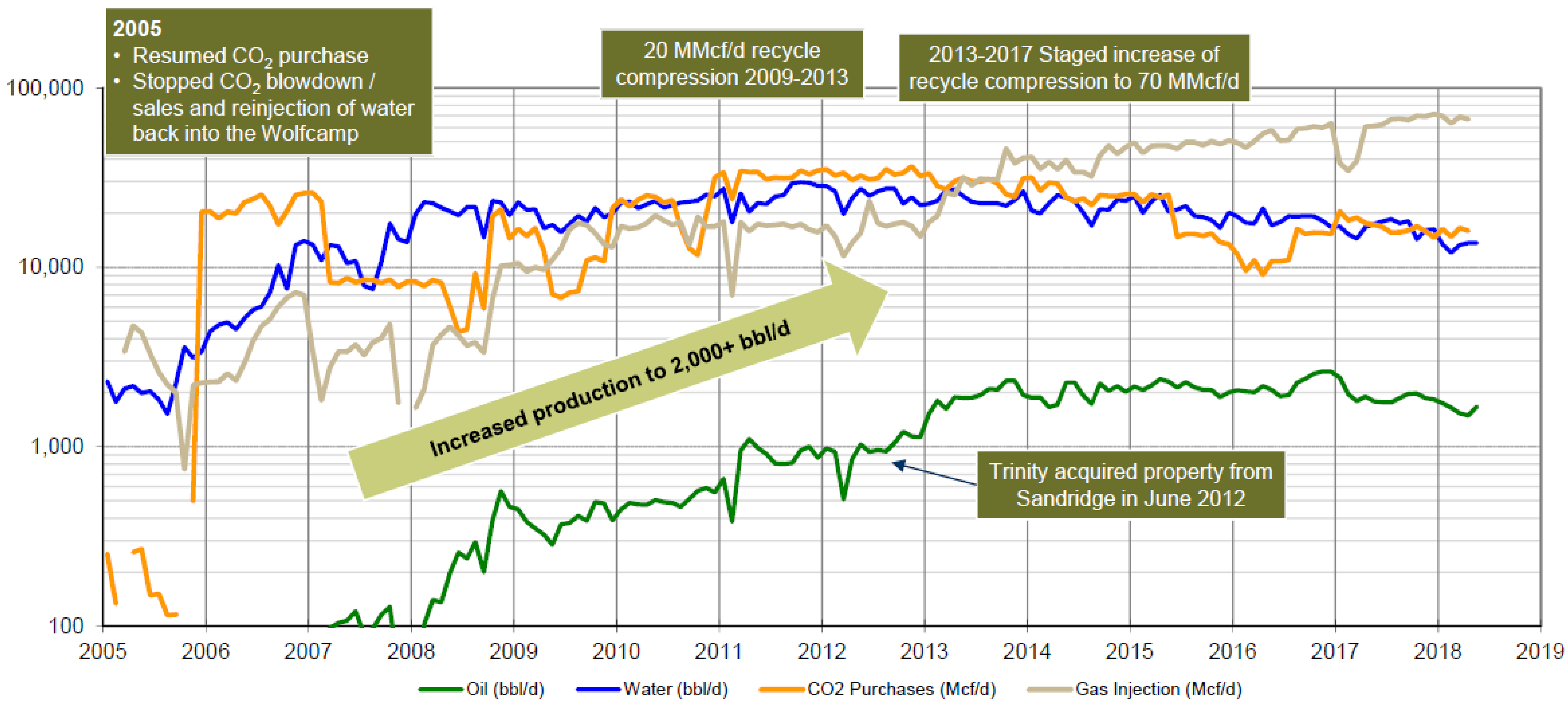


Wellman Unit: Successful Re-initiation of the CO_2 Flood

Oil production has gradually risen above 2,000 bbl/d since the re-initiation of the flood

Commentary

- CO_2 flood under Trinity management (2006-present)
  - Re-started CO_2 injection, discontinued in-zone water injection, and instituted workovers to optimize perforations
  - In 2009 installed 20 MMcf/d recycle compression facility
- July 2012 – Trinity acquired property from Sandridge
  - Accelerated workover program and began staged increase in recycle compression
  - 2011 - 2013 CO_2 purchase constant at ~30 MMcf/d
  - 2013 – present reduced CO2 purchases and began sharing supplies with George Allen project



Historical Reservoir Performance

Primary Depletion (1950 – 1979)

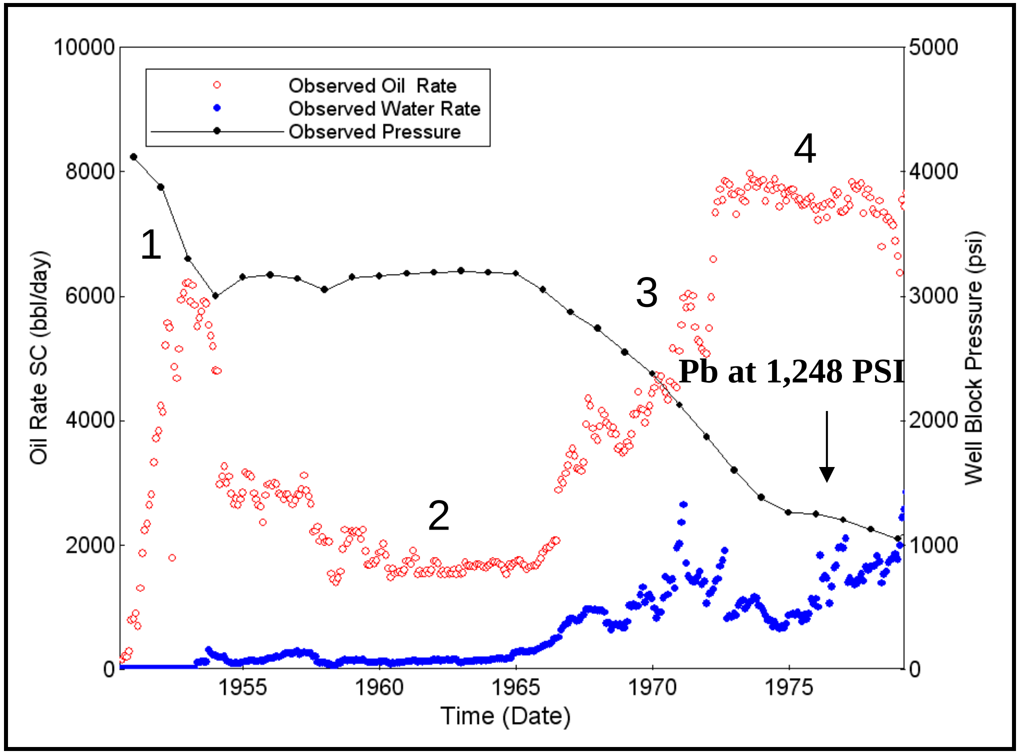
1) 1950-53 oil rate peaked 6 MSTBD

2) 1954 allowable restrictions oil rate reduced to 3, then 1.7 MSTBD

3) 1966 oil rate peaked 8 MSTBD

4) 1976-79 produced below P_b until reached minimum 1,050 psig

Cum. Oil: 41.8 MMSTB
RF: 34.6%

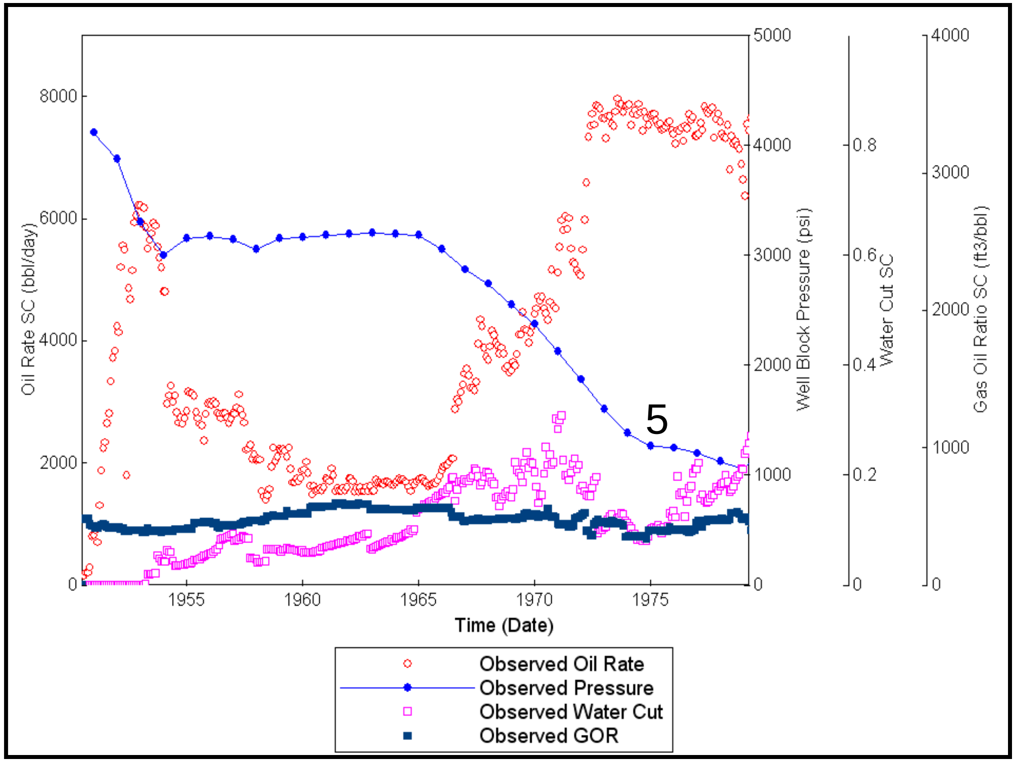


Historical Reservoir Performance

Primary Depletion (1950 – 1979)

5) 1976-79 GOR did not increase
secondary gas cap formed.
H_2O cut: from 10 to 25%

Cum. Oil: 41.8 MMSTB
RF: 34.6%



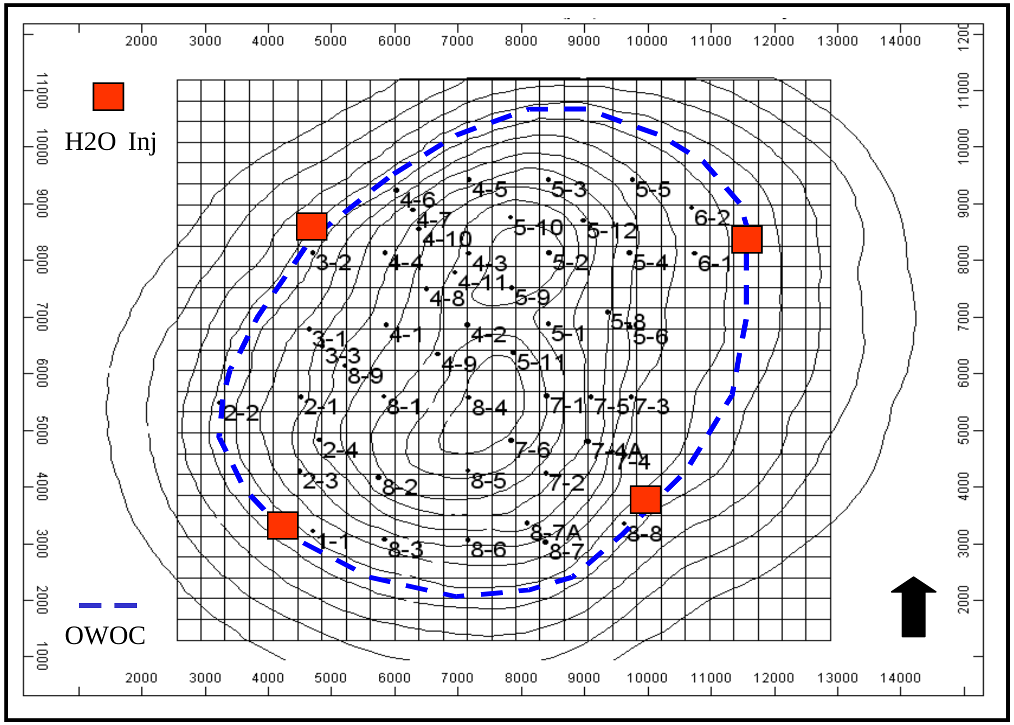
Historical Reservoir Performance

Waterflooding (1979 – 1983)

1979 - four flank H_2O injectors re-pressurize (MMP), re-dissolve part of the gas, displace oil upward

Cum. Oil: 23.9 MMSTB

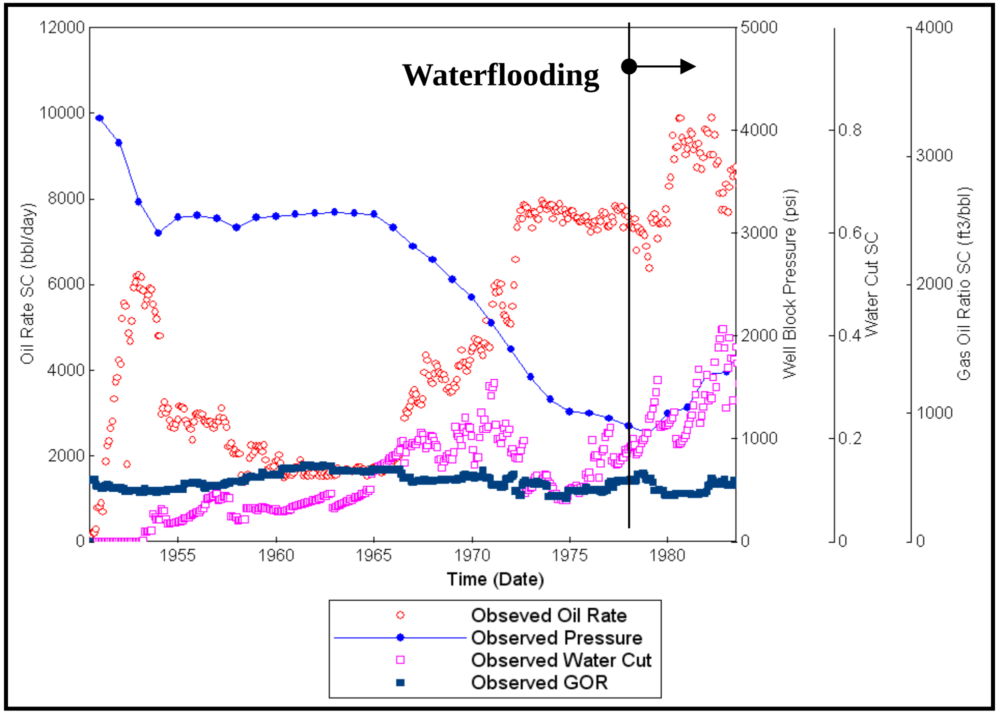
Sec. RF: 19.5%



Historical Reservoir Performance

Waterflooding (1979 – 1983)

- Pressure increased from 1,050 to1,600 psig prior CO_2 (1983)
- Water cut from 25 to 40% GOR aprox. constant
- Water cut controlled by plug downs
- Oil rate increased to 9 MSTBD



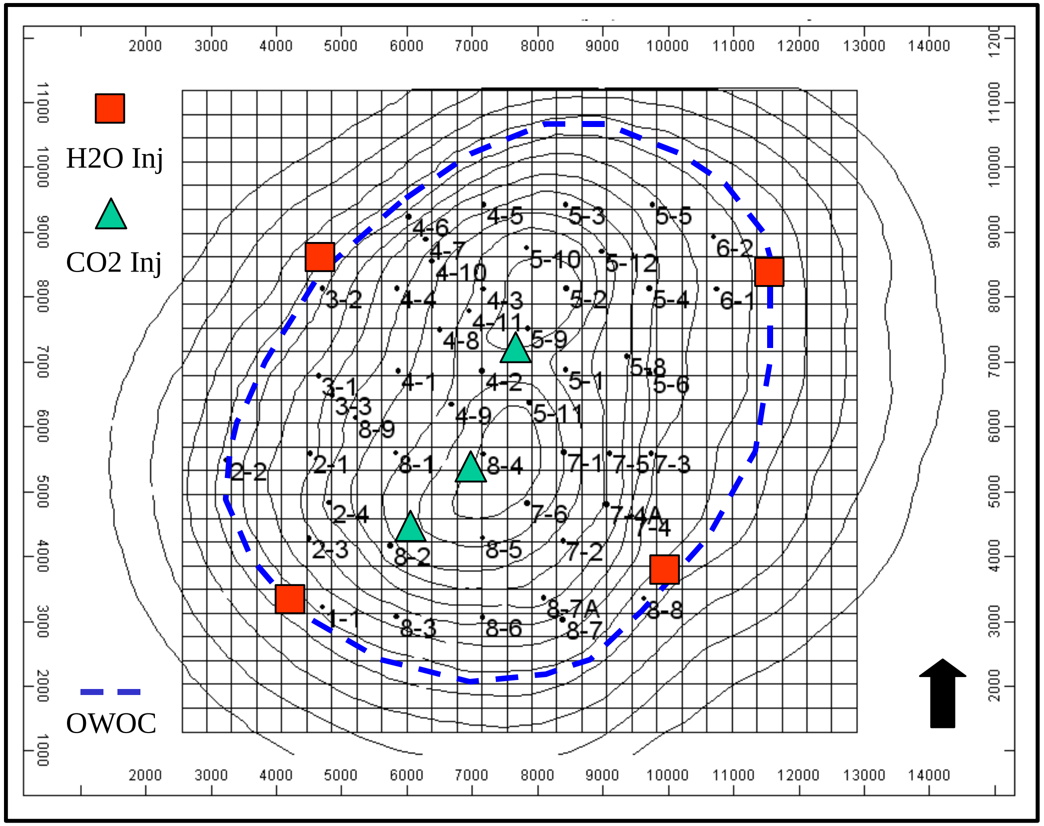
Historical Reservoir Performance

CO_2 Injection (1983 – 1995)

- **1983-89 - Three crestal Injectors to displace oil downward and reduce Sor**

Cum. Oil: 6.3 MMSTB

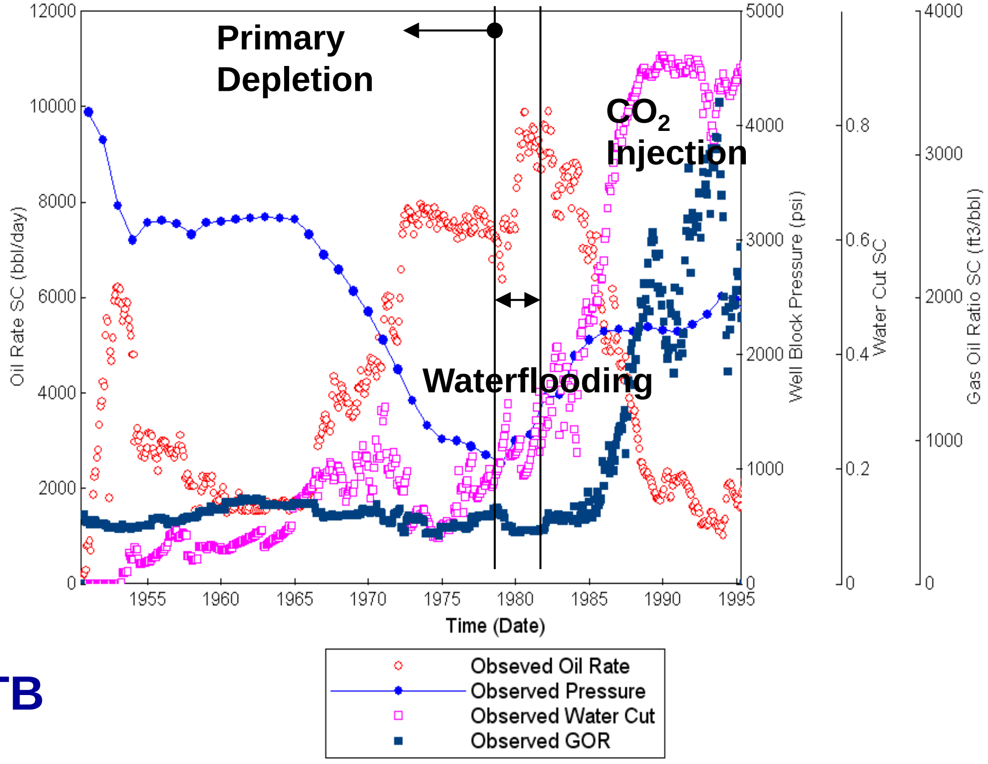
Ter. RF: 5.4%



Historical Reservoir Performance

CO_2 Injection (1983 – 1995)

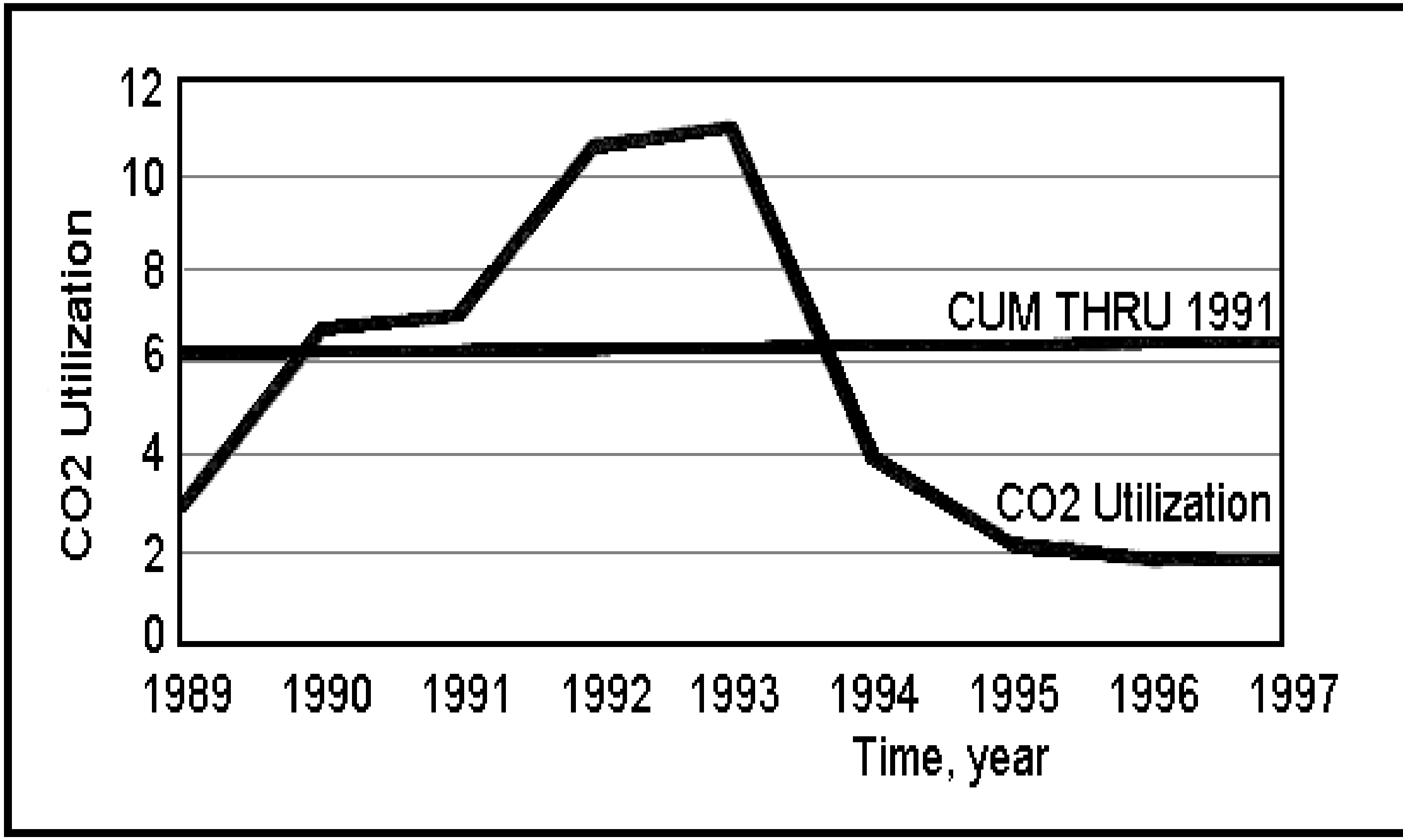
- **1984-89, CO_2 Inj. From 5 to 15 MMCFD.**
- **1985, break water cut from 40 to 85%. (ESP's, leaks, corrosion)**
- **GOR peaked to 3000 SCF/STB (mostly CO_2)**
- **Pressure from 1600 to 2,300 peaked at 2,500 psig in 1994.**



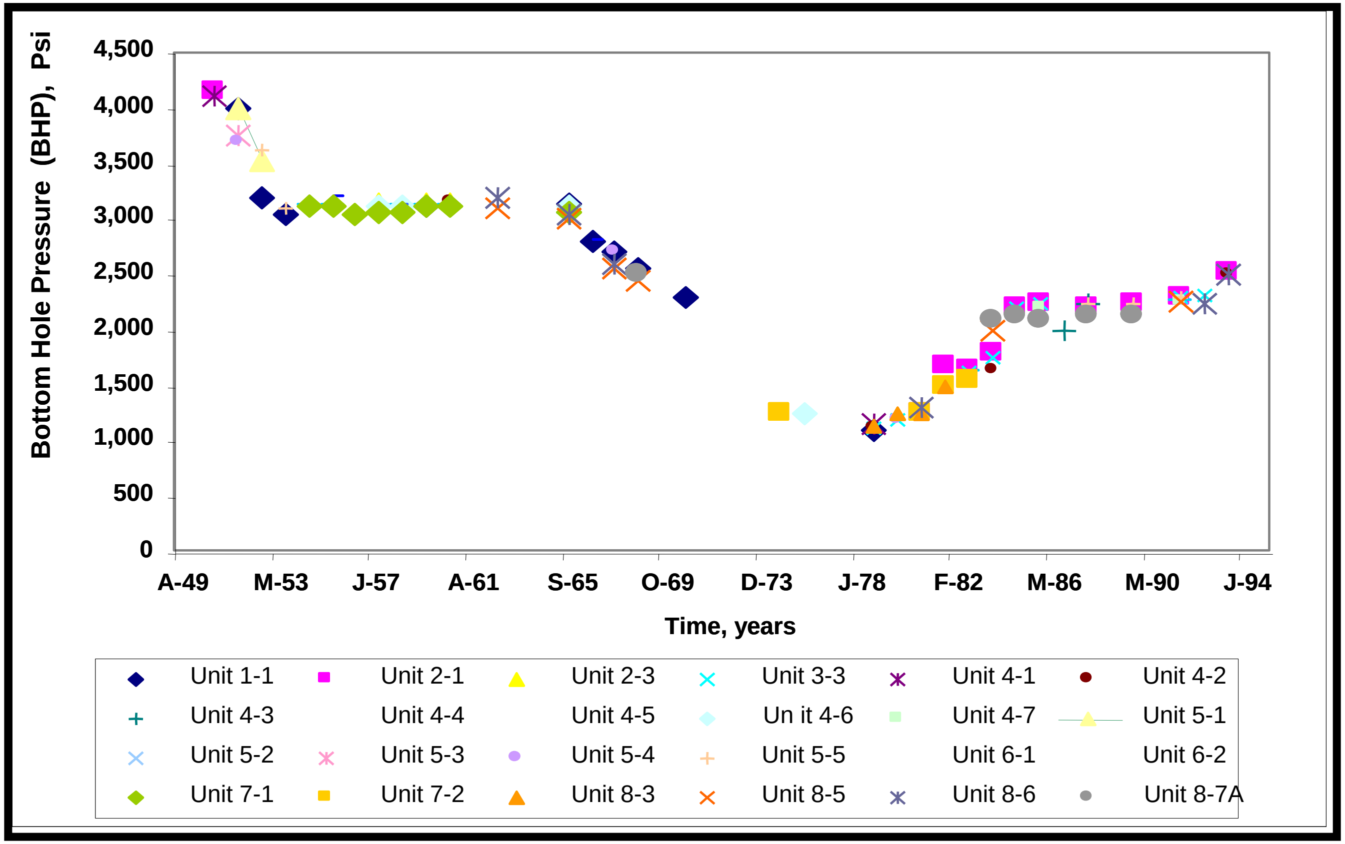
Cum. Oil: 6.3 MMSTB

Ter. RF: 5.4%

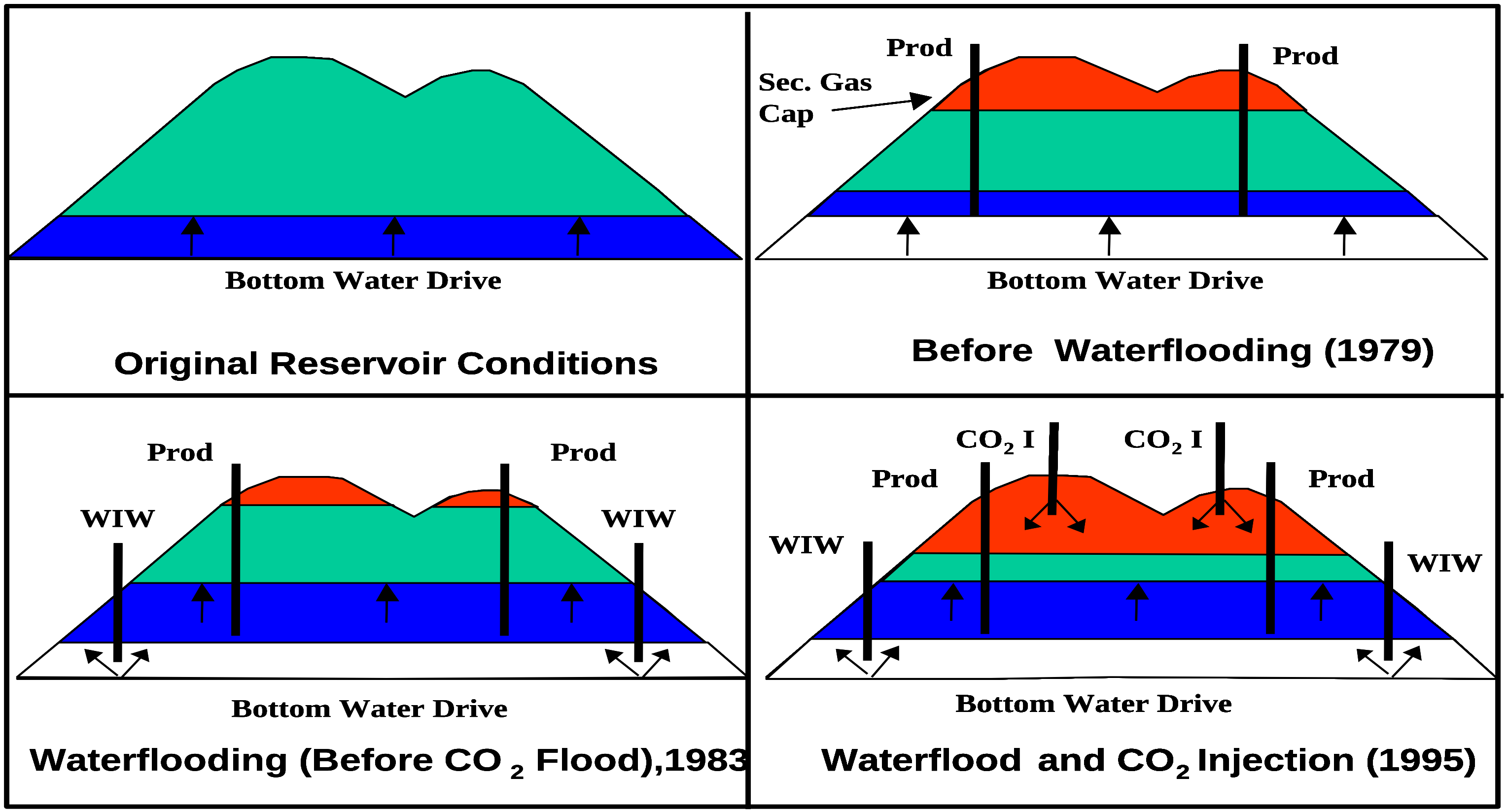
Wellman Unit Annual CO_2 Utilization



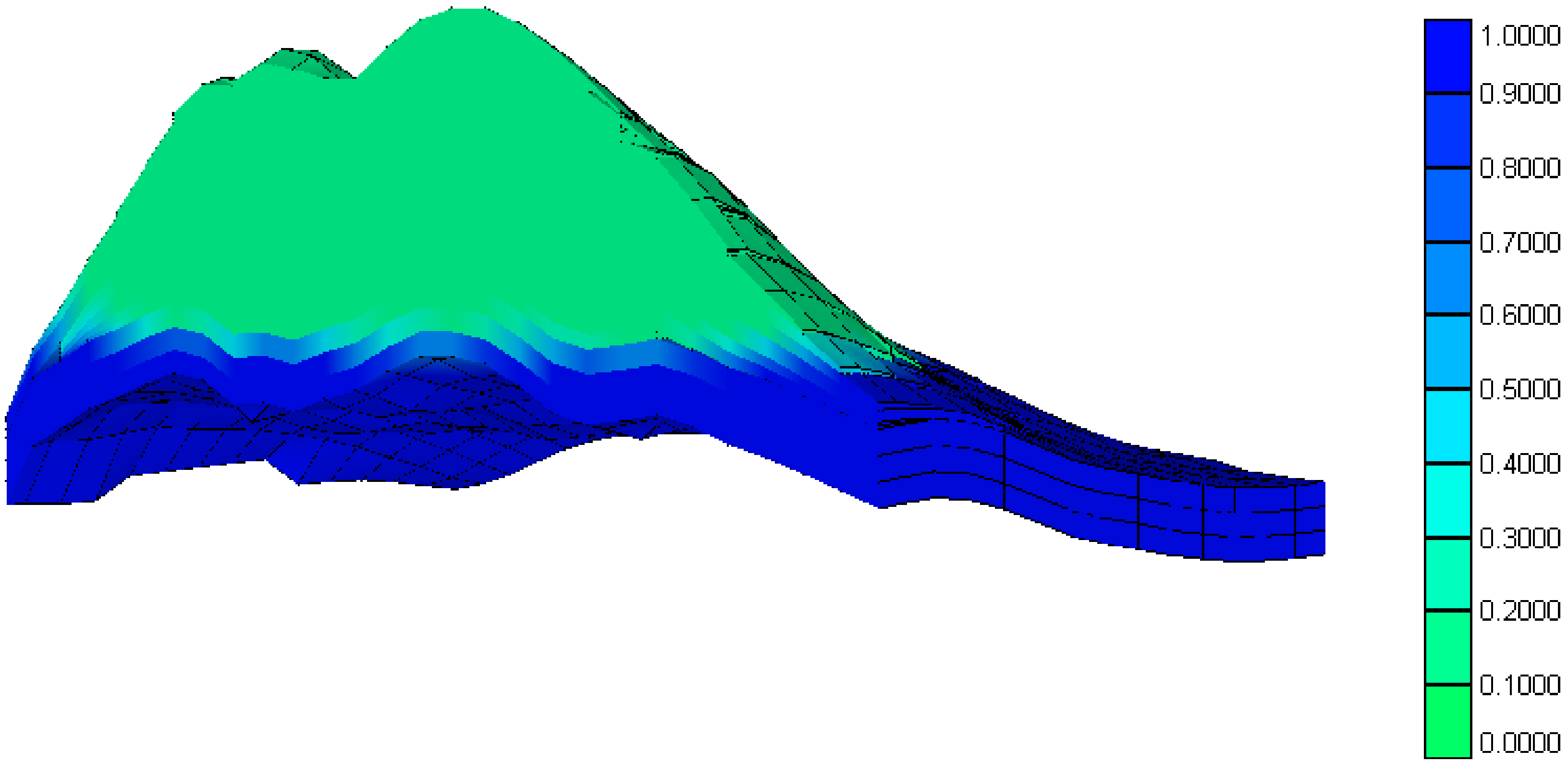
Wellman Unit Individual Static Bottom Hole Pressure



Chronological Stages of Depletion

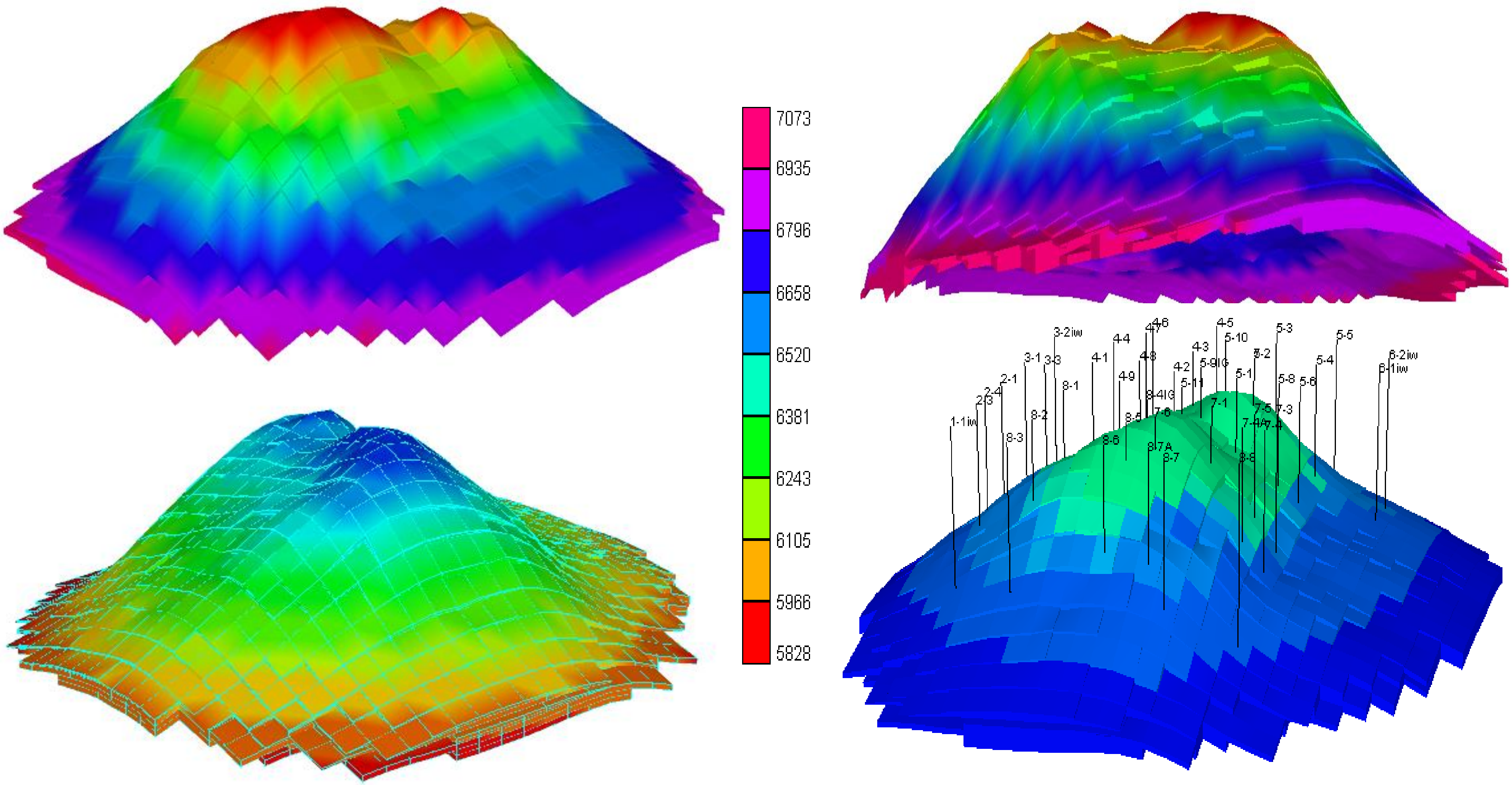


INITIAL WATER DISTRIBUTION PROFILE SHOWING WOC, TRANSITION ZONE AND IRREDUCIBLE WATER SATURATION (20%) IN THE OIL ZONE



Simulation Model

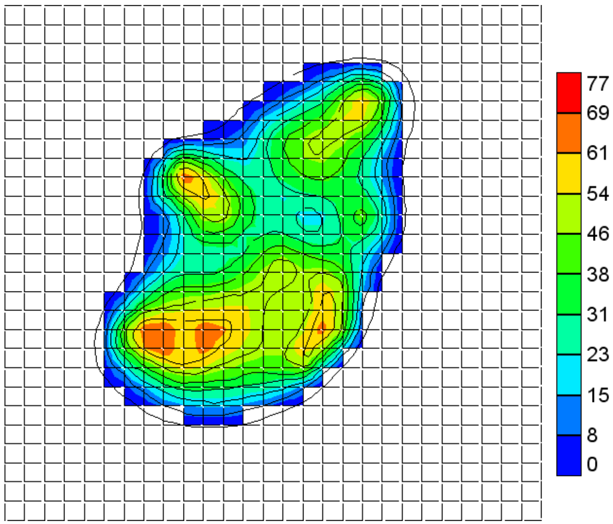
3D – Structure Development



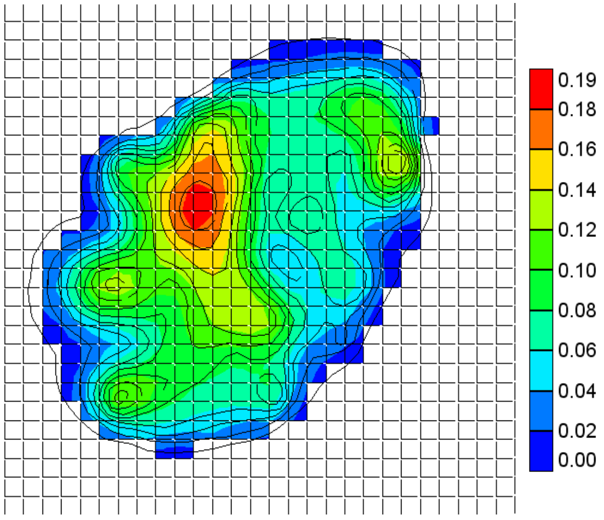
Simulation Model

Input Data

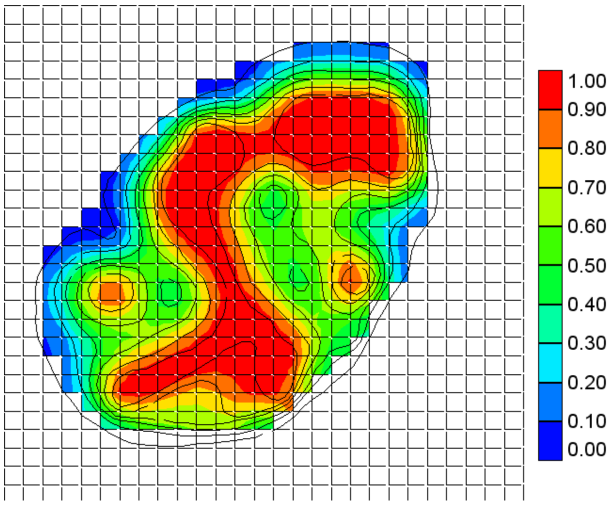
Gross Thickness

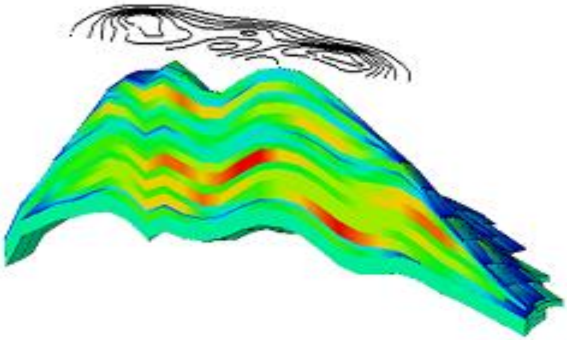


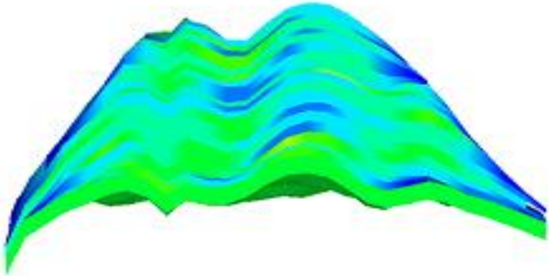
Porosity

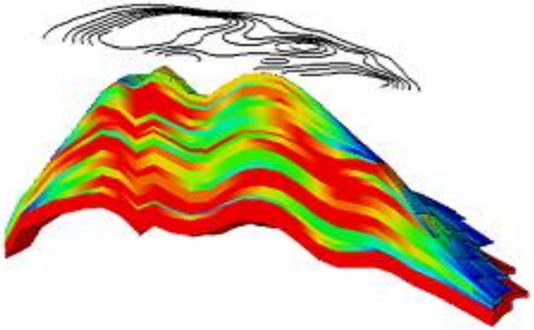


Net to Gross Ratio



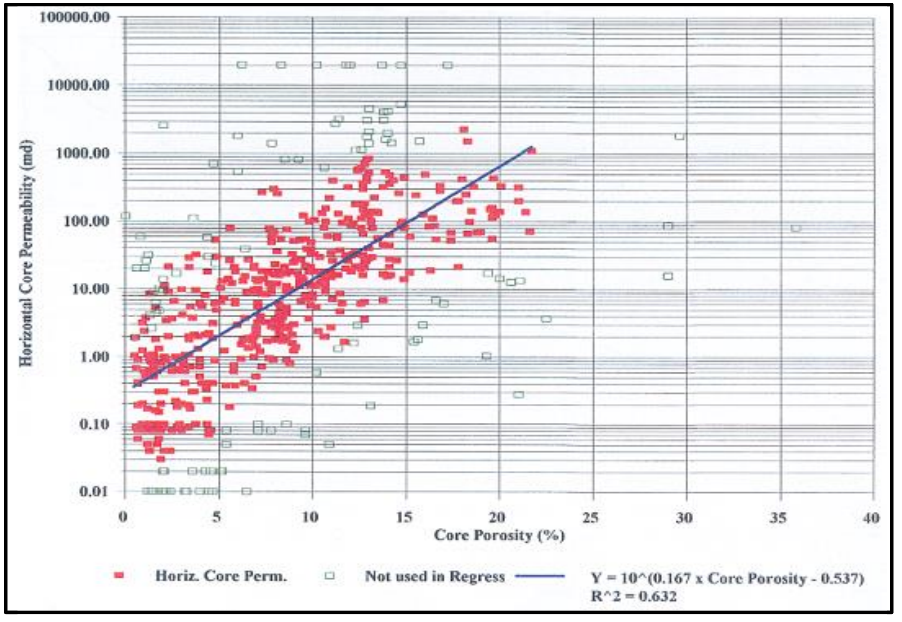




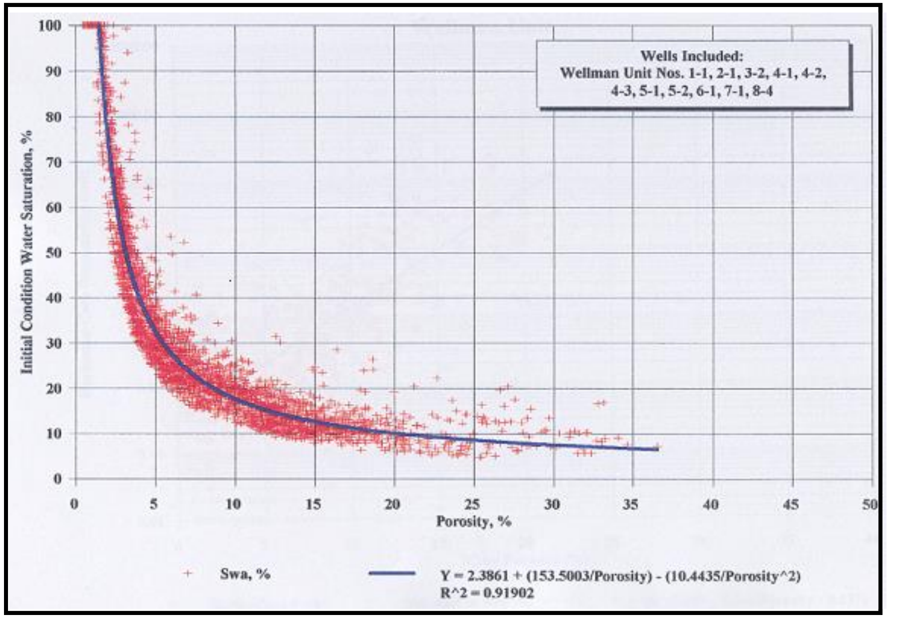


Simulation Model

Input Data



Permeability



Swc, aprox 20% for Φ = 8.5%

- Use previous estimations from correlations between open logs and core measurements

$$K = 10^{(0.167 * \text{Core porosity} - 0.537)}$$

- Relationship may not be representative due to fractures and vugular porosity

Water Saturation

Simulation Model

Input Data

Fluid Properties

- Use PVT properties contained in previous lab and reservoir studies

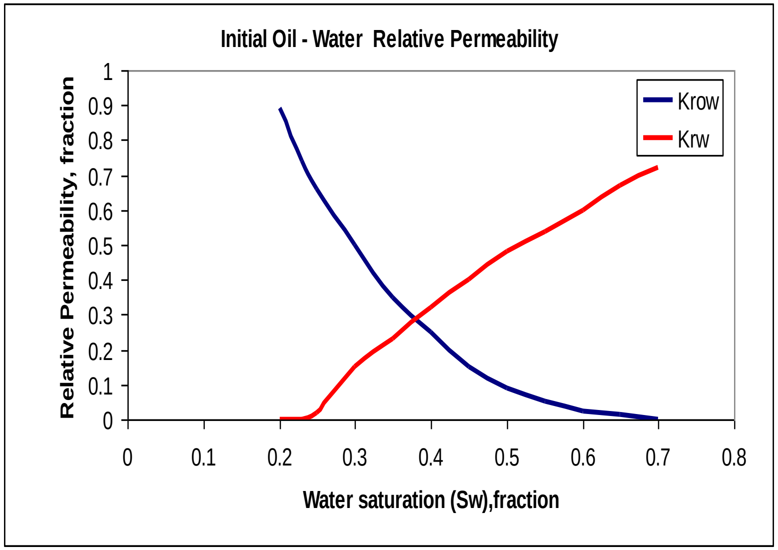
  - Bubble point: 1248 – 1300 psig
  - Rs, 400-500 SCF/STB
  - Oil Gravity, 43 API
  - OFVF, 1.30 RB/STB
  - Oil Viscosity, 0.4 cp
  - Black oil fluid type

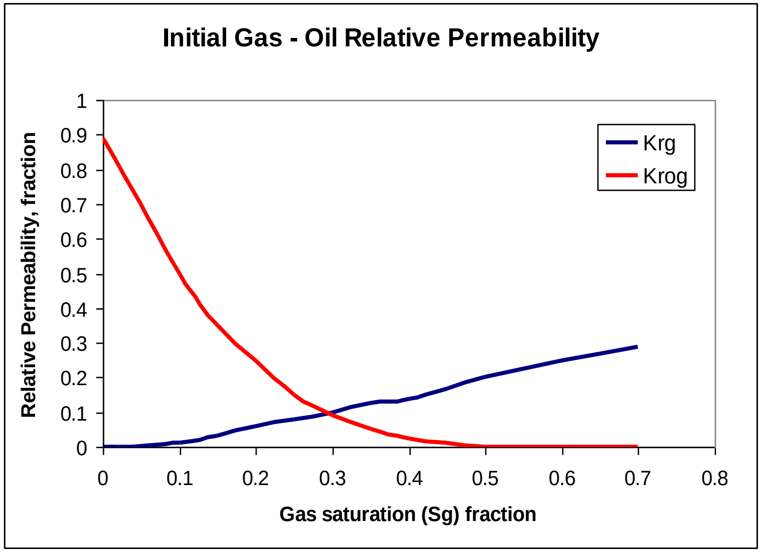
Relative Permeability

- Special core analysis for core well No. 7-6 included measurements on only two samples with a low non-representative permeability
- Use functions derived from Honarpour's correlation (past studies)

Simulation Model
Input Data

Initial Oil-water and gas Relative Permeability

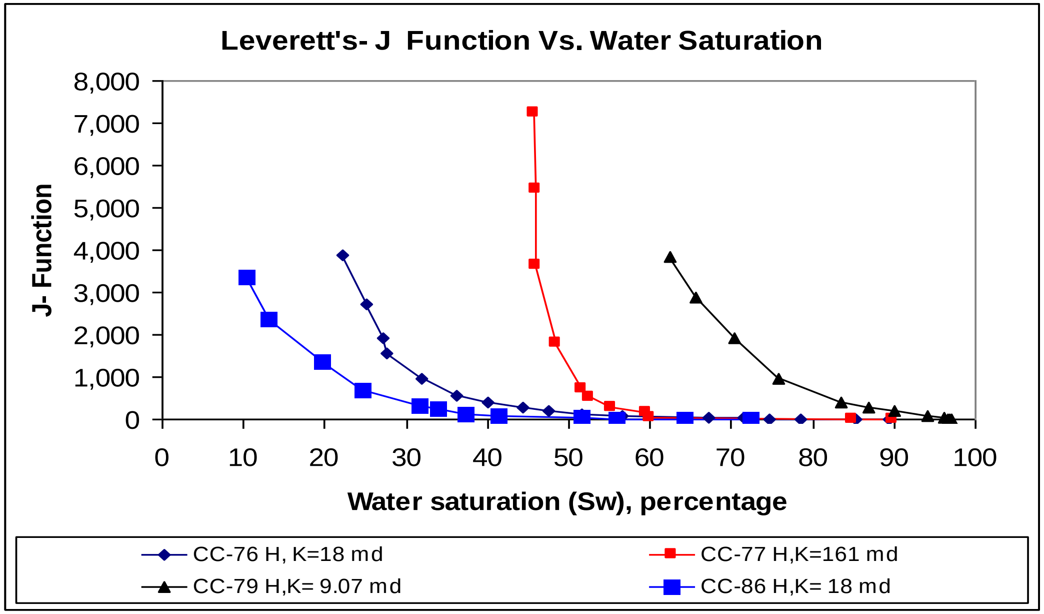




Simulation Model
Input Data

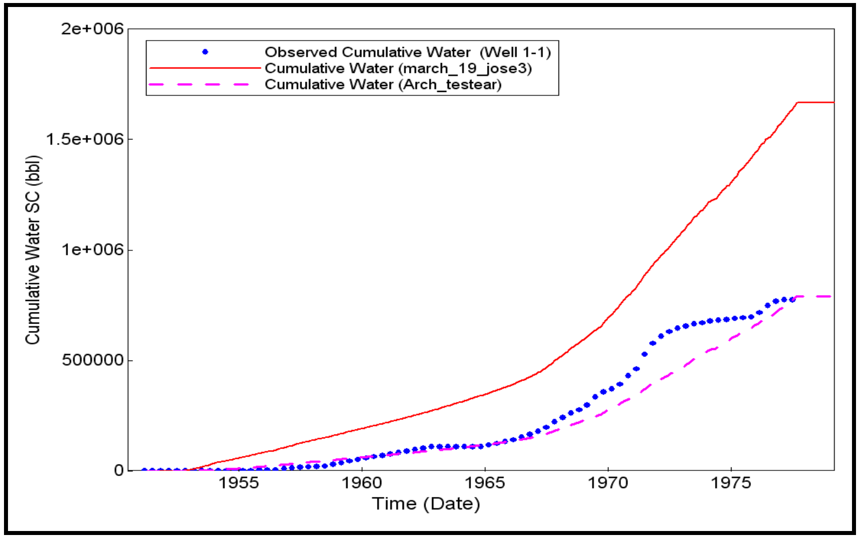
Capillary Pressure Data

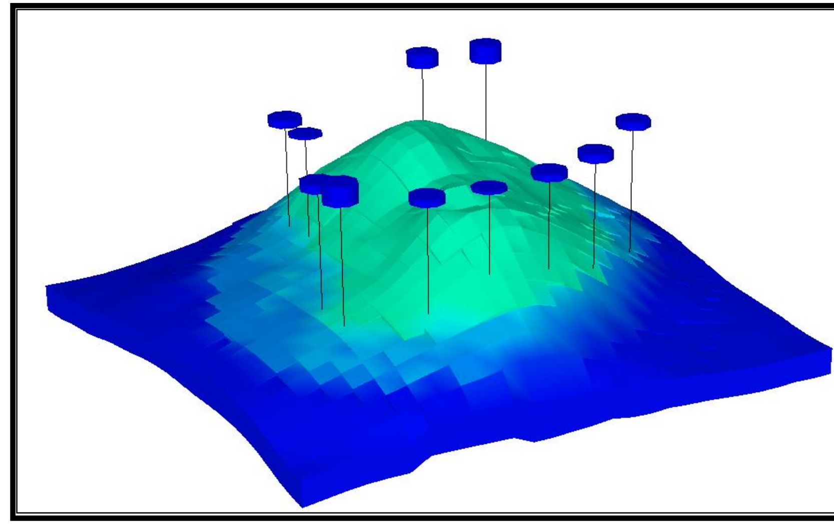
- Only 4 samples , K> 1 md (Special core Analysis)
- Data normalized by Leverett's J-function
- Shape suggests lack of capillary transition zone
- Good vertical communication capillary effect "no significant"

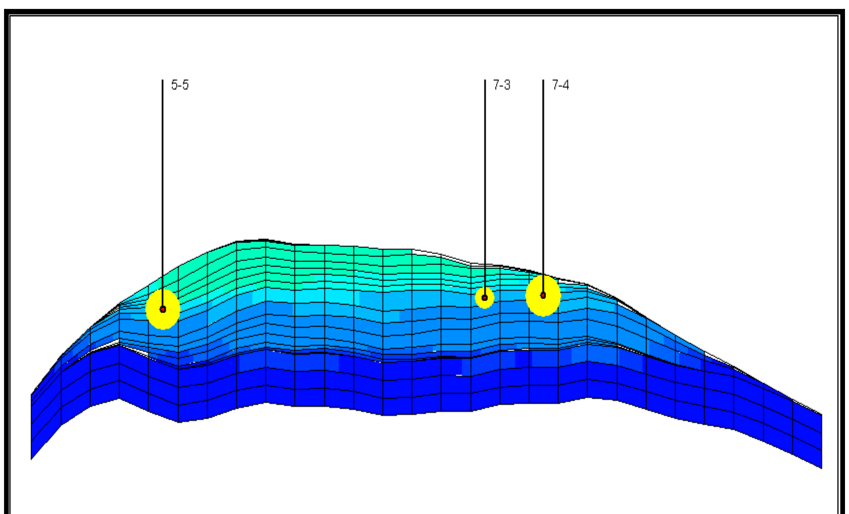


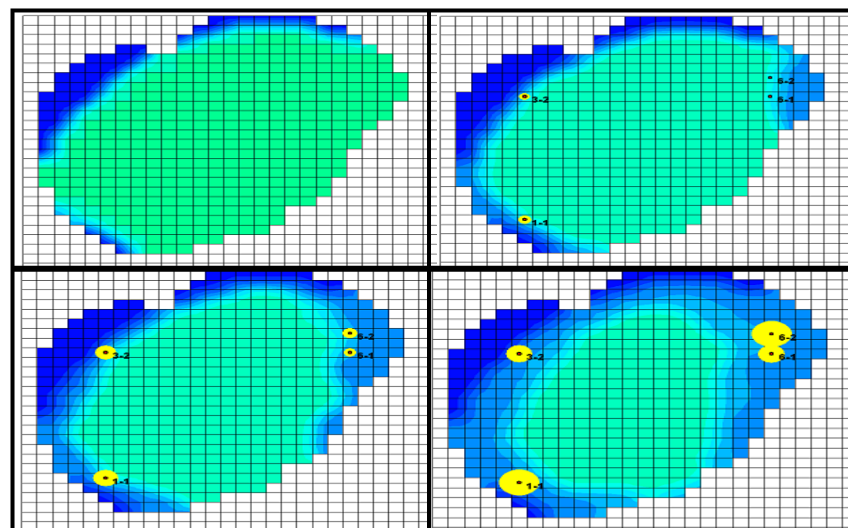
Results: Primary Depletion

Diagnosis



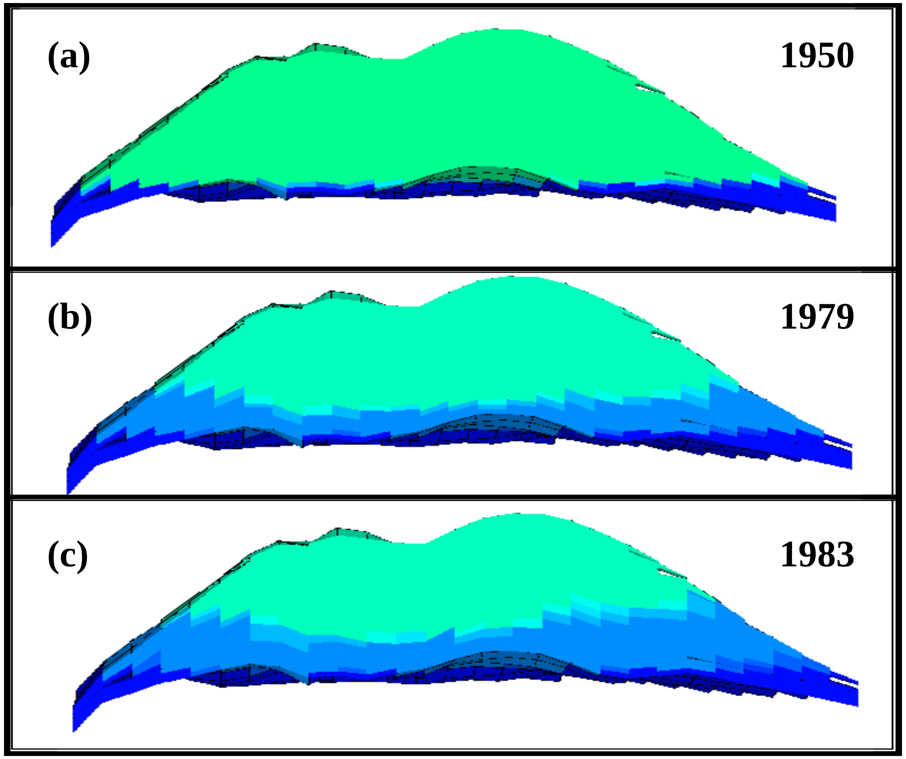






Results: Waterflooding

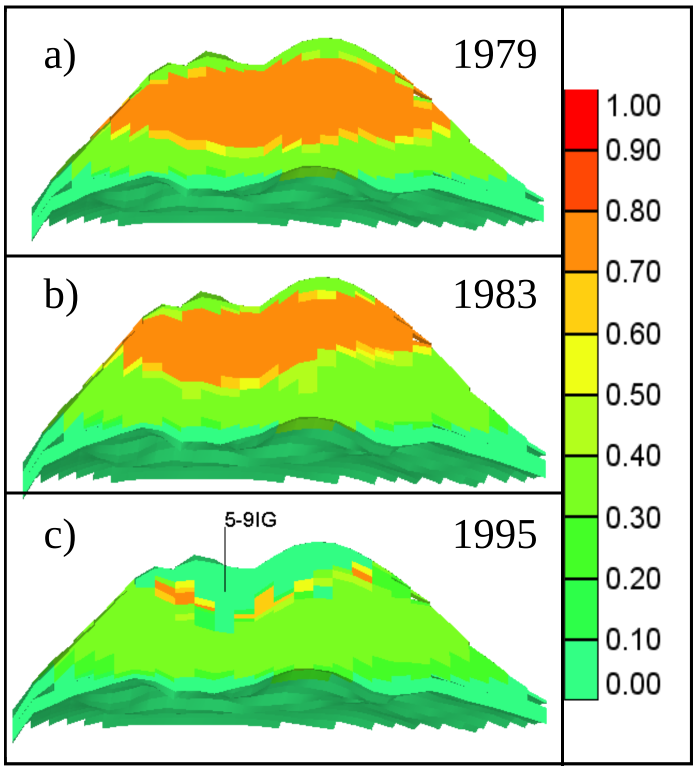
WOC Movement



208 ft

210 ft

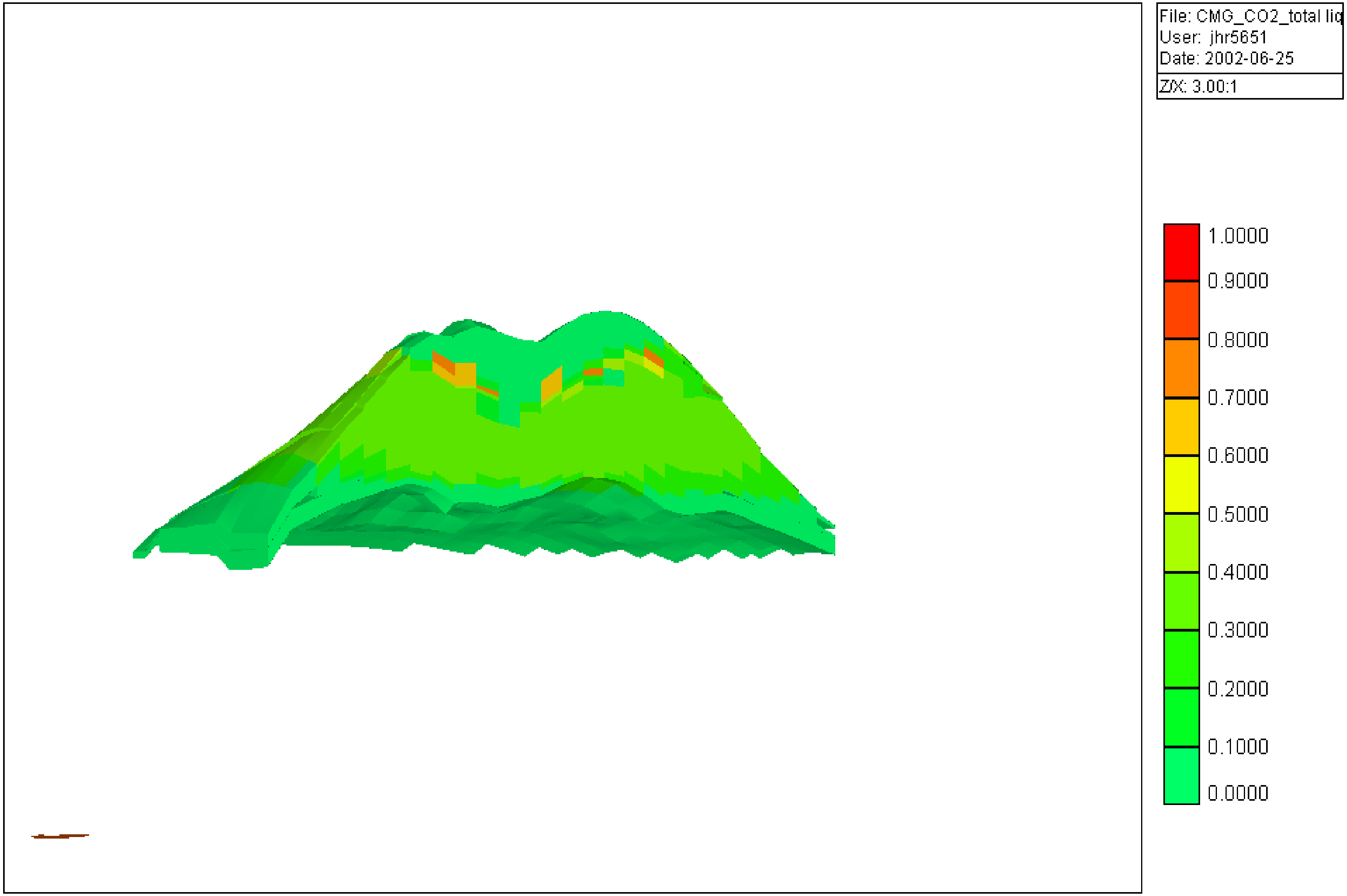
Results: CO_2 Injection
Chronological Oil Saturation Distribution



a) Primary depletion

b) Waterflooding

c) CO_2 miscible flooding
Oil saturation considered overestimated due to the excess of oil production



File: CMG_CO2_total liq
User: jhr5651
Date: 2002-06-25
Z/X: 3.00:1
1.0000
0.9000
0.8000
0.7000
0.6000
0.5000
0.4000
0.3000
0.2000
0.1000
0.0000

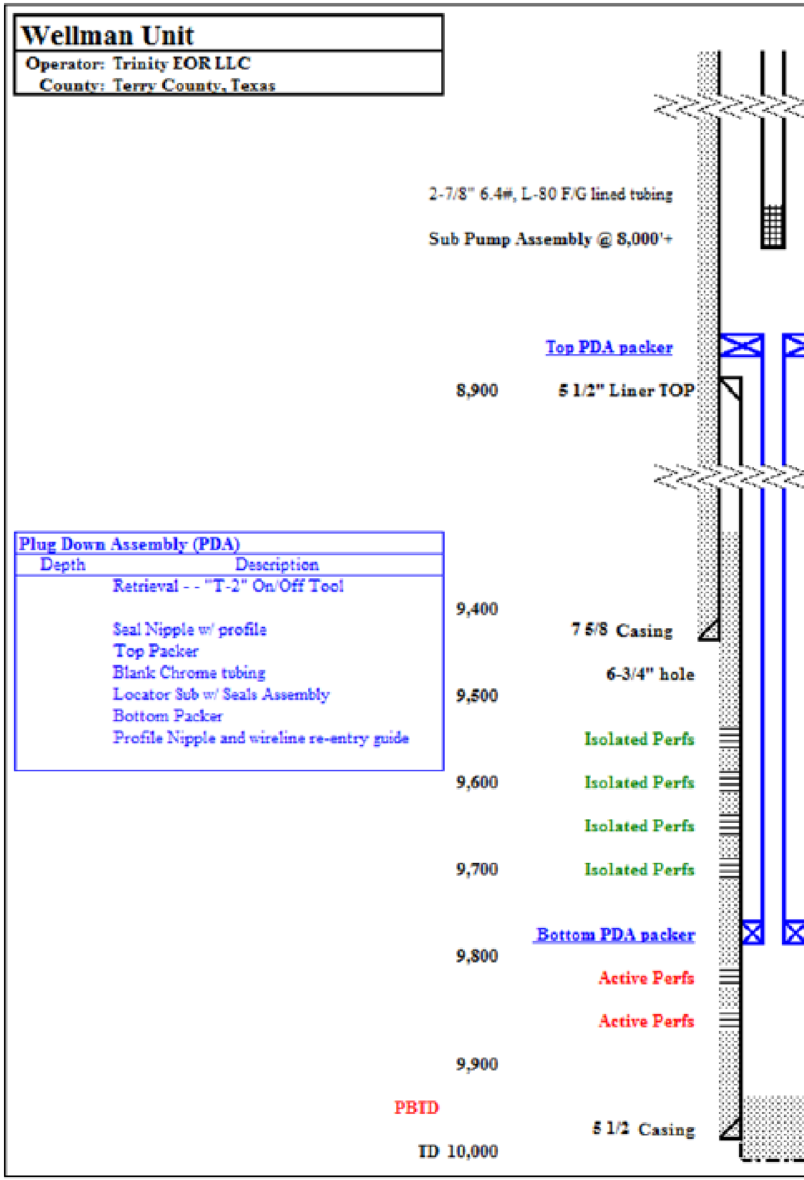
Plug-down operation isolates shallower high-GOR perforations and adds deeper perforations tracking the oil column

Plug-Down Process

- Objective
  - Optimize total oil production and maximize total oil recovery through flood surveillance and targeted perforations
  - Perforations in wells track the movement of the oil and ROZ column
- Plug-Down Operation
  - Candidate wells identified by increasing GOR; ability to plug down well or identify better quality reservoir at given perf depth in adjacent wells
  - Old perforations are squeezed and isolated in the plug-down procedure using packers and an isolation string
  - Two-packer system with tubing in-between straddles the perforation now in the CO_2 cap
  - New perforation intervals selected are generally 10 to 20 ft below any CO_2 indicated on the logs
  - New perforations target ~10 ft at a time
- Timing Considerations
  - Generally 18 to 24 months per well
  - 10 plug-downs expected per well annually
  - Intervals selected so that the next interval can be isolated (minimum 20 ft of separation)
  - Once OWC reaches initial original OWC of about -6,680 ft TVDSS more plug-downs will not be needed

Year	Total Cost	Number of Plug-Downs	Average Cost
2016	$2.34MM	9	$0.26MM per plug-down
2017	$1.64MM	4	$0.41MM per plug-down
2018+	$3.5MM	10	$0.35MM per plug-down

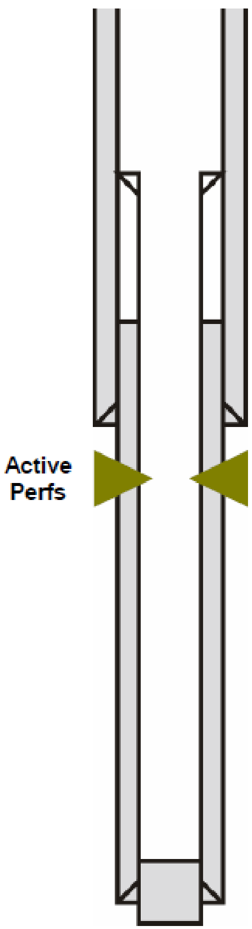
Typical Wellbore Schematic



Wellman Unit: Illustrative Plug-Down Process

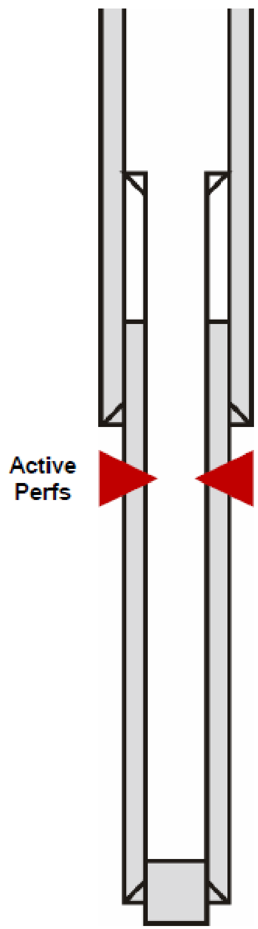
1

- Active perforations at oil column depth
- **High oil production**
- Low GOR



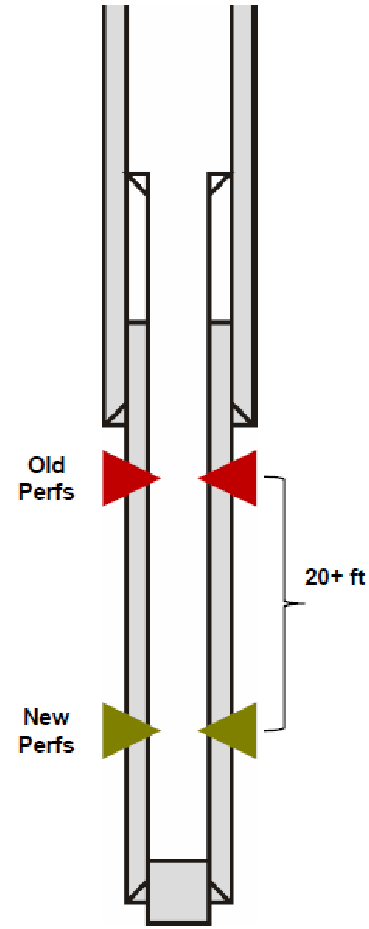
2

- Oil column depth drops below perforations
- Lower oil production
- **Increasing GOR**



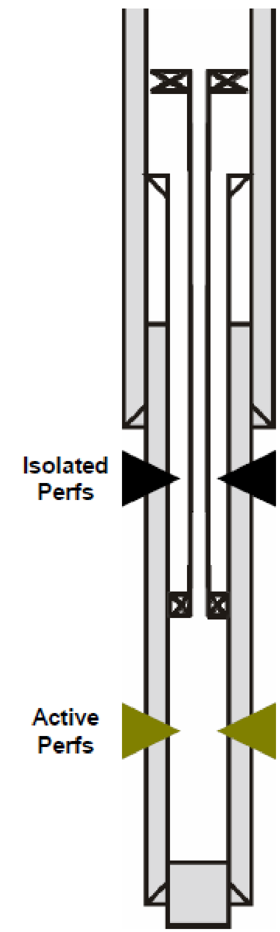
3

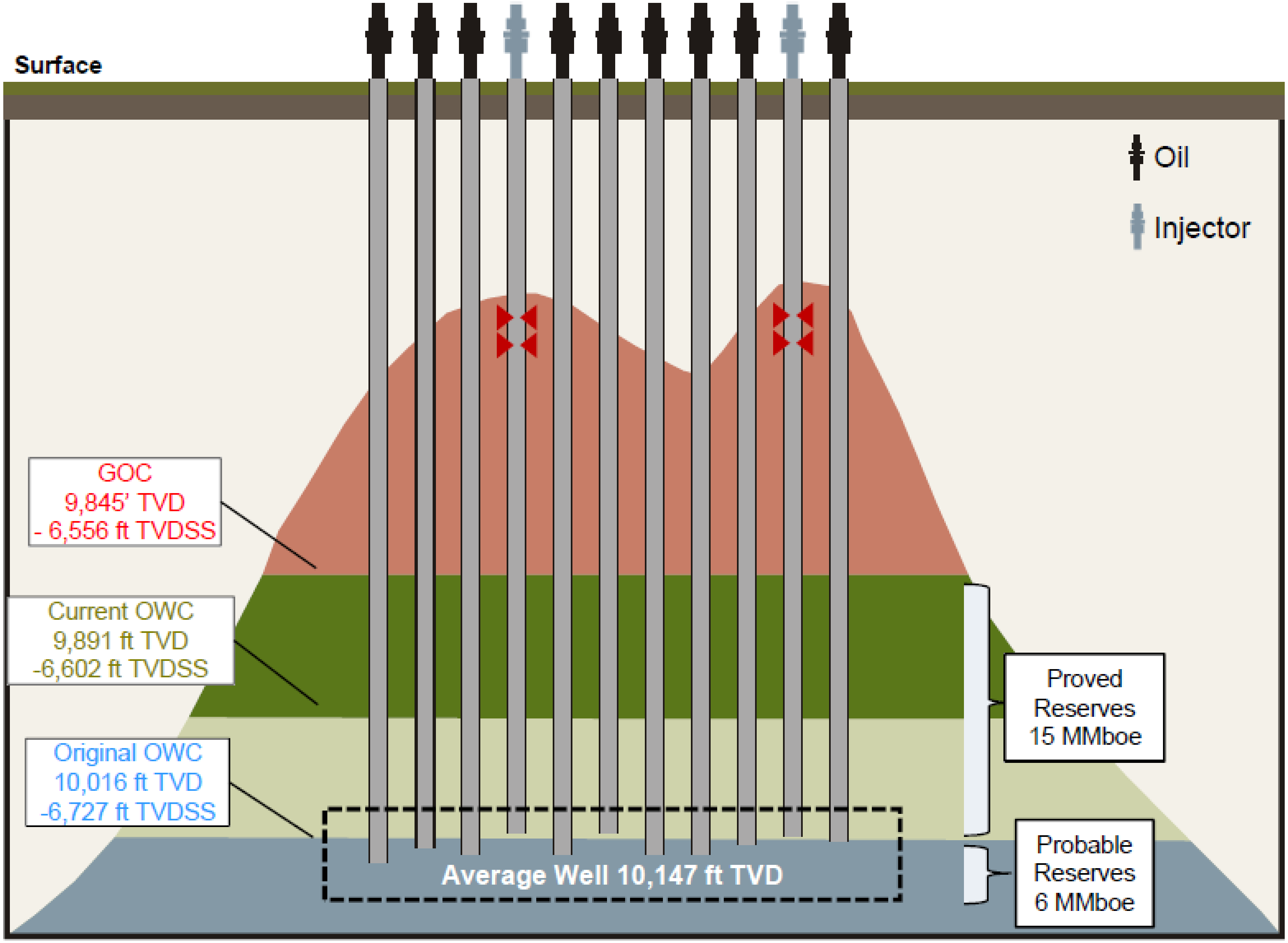
- New perforations selected 20+ ft below existing
- Squeeze old perfs
- If reservoir quality is low, adjacent well is selected



4

- Plug isolates upper perforations
- **High oil production**
- Low GOR





Surface
Oil
Injector
GOC
9,845' TVD
- 6,556 ft TVDSS
Current OWC
9,891 ft TVD
-6,602 ft TVDSS
Original OWC
10,016 ft TVD
-6,727 ft TVDSS
Average Well 10,147 ft TVD
Proved Reserves 15 MMboe
Probable Reserves 6 MMboe

Recycle Compressor

NGL Recovery Plant

Tank Battery

Production Separators


June 2018

Conclusions

- CO_2 flooding in the W.U. has performed exceptionally well due to gravity stable displacement above MMP.
- Reducing pressure from above the MMP to near the MMP does not reduce efficiency in laboratory. BHP in the W.U. could be reduced to near the MMP with no reduction in displacement efficiency.
- The reduction in CO_2 purchases would be a positive benefit. The reduction in reservoir pressure is constrained by voidage replacement issues.
- Excellent sweep and displacement efficiency is observed in the lab and the field with residual oil saturation in strong agreement with lab and gas cap.
- Over 130 Bcf of CO_2 has been injected and sequestered in the gas cap.
- Gravity drainage combined with excellent well diagnostics and monitoring results in outstanding recovery factor of 63%.

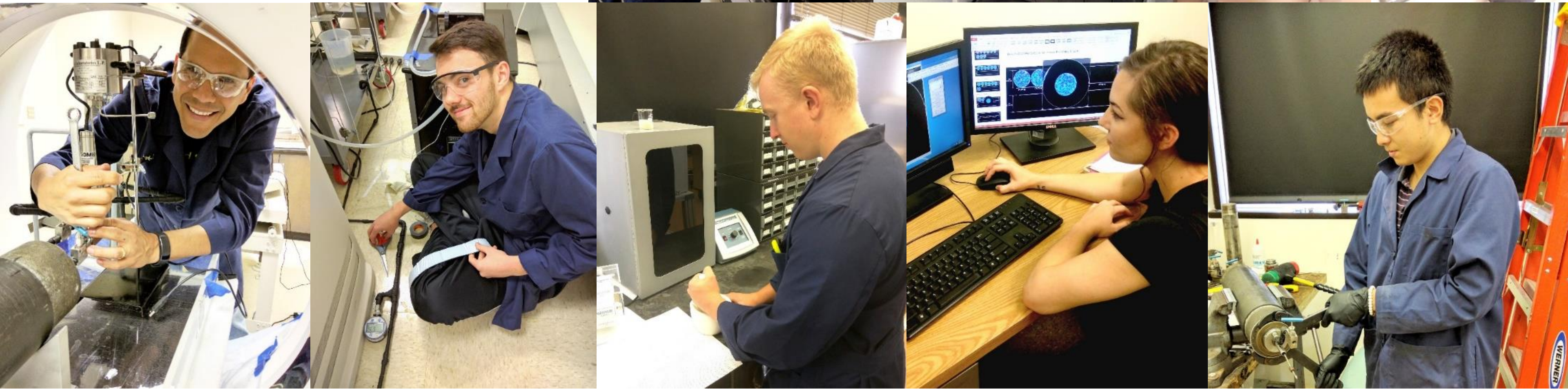
WARNING: GRAPHIC CONTENT

The following image and/or content may be disturbing to some viewers.
Viewer discretion is strongly advised

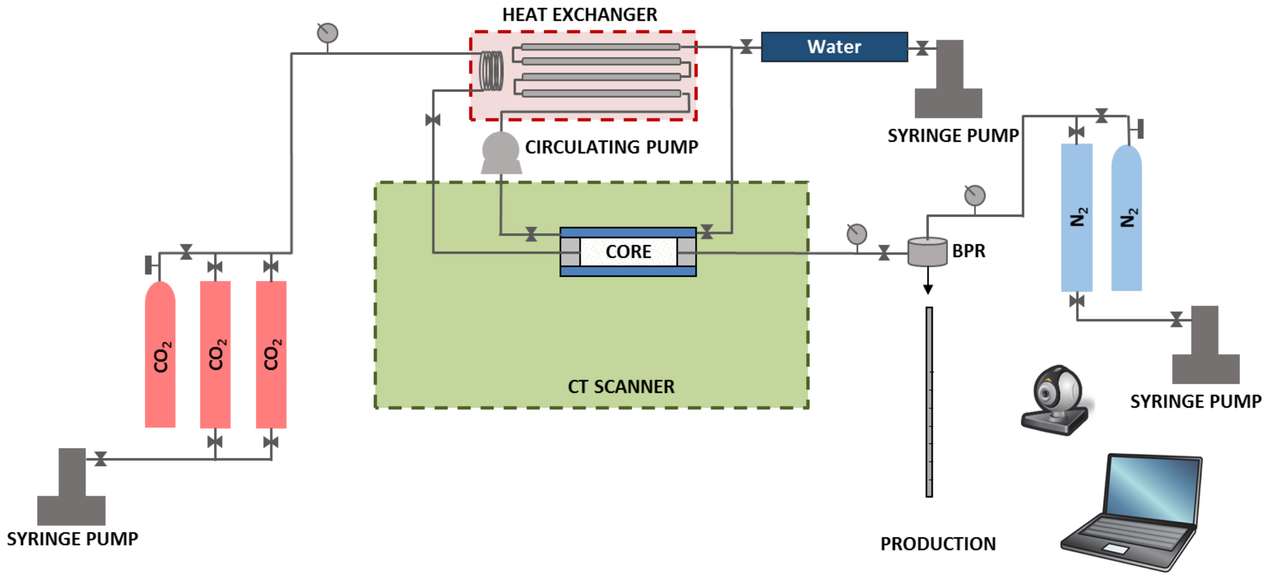
ADVERTENCIA: IMAGENES FUERTES

La siguiente imagen y/o contenido podria resultar perturbador para algunas audiencias
Se aconseja discrecion

Team Effort



Core-flooding + CT scanning integrated equipment



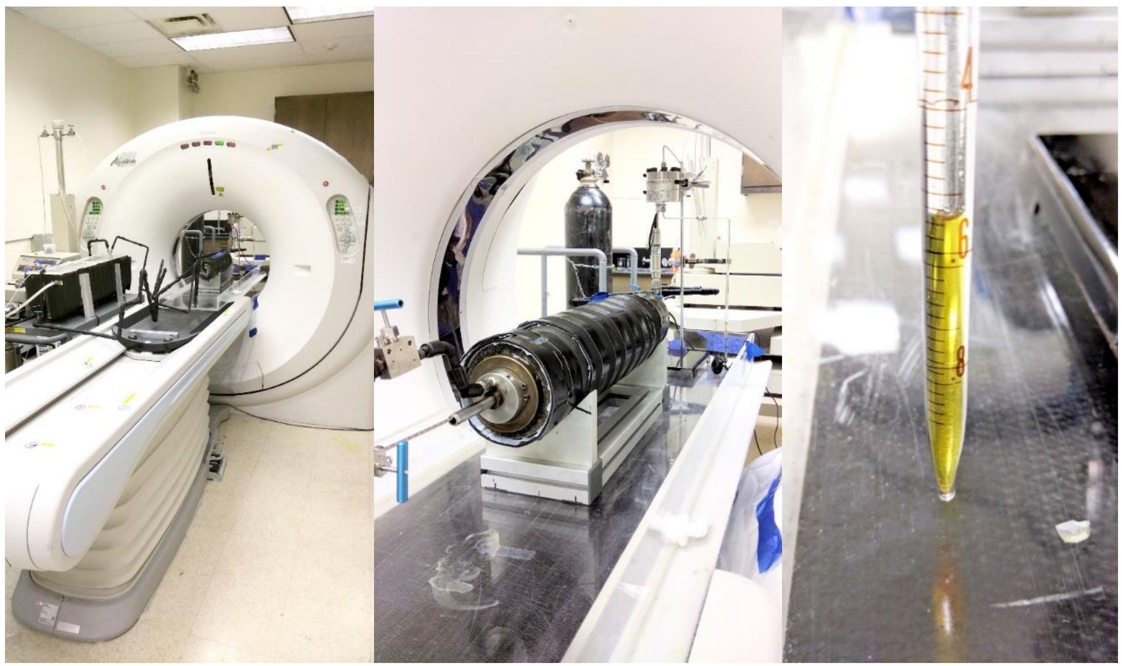
Reservoir temperature

Reservoir pressure

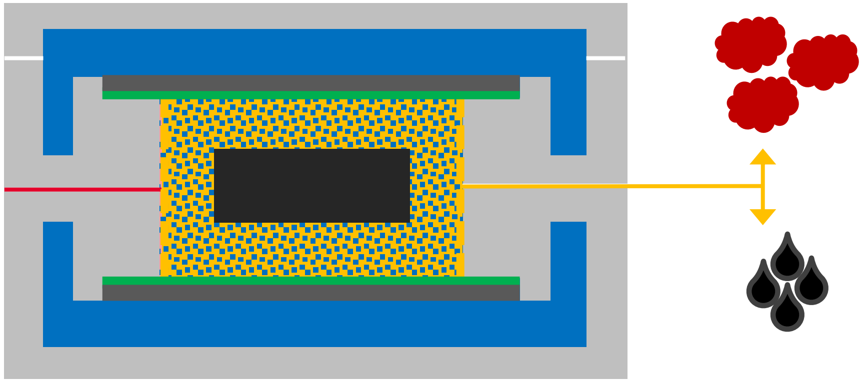
Confining pressure

CT Scanning capability

Core-flooding + CT scanning integrated equipment



CO_2 Injection in shale physical simulation



- CO_2 is injected
- Soaking is allowed (0 – 22 hr)
- CT Scanning is done periodically
- CO_2 is displaced with fresh CO_2
- The pressure is kept constant

Produced oil

1 2 3 4

1. – Original crude oil used for core re- saturation
2. – Effluents | Shale | 2500 + 3500 psi |22 hr
3. – Effluents | Sandstone | 2500 psig | 3rd Cycle | 3500 psig | 22 hr
4. – Effluents | Sandstone | 2500 psig | 1st & 2nd cycles | 22 hr

Vaporizing gas drive

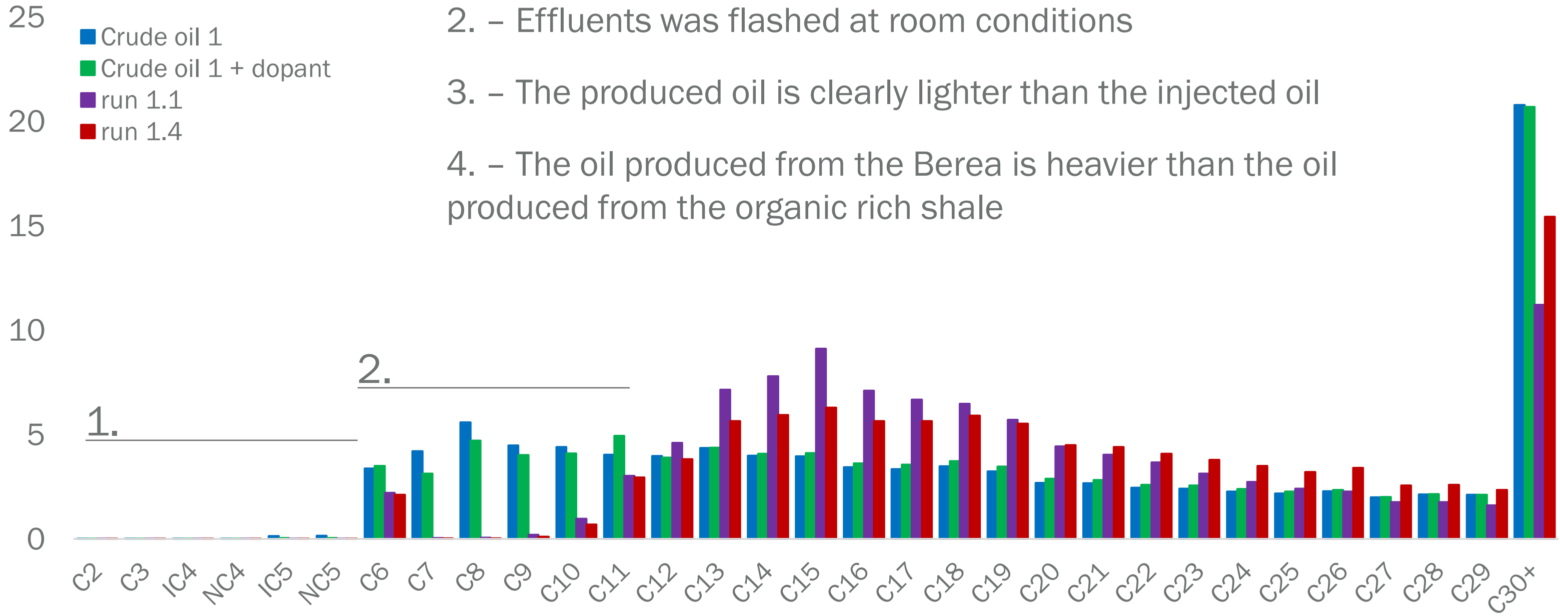
Produced oil

1. – Dead oil

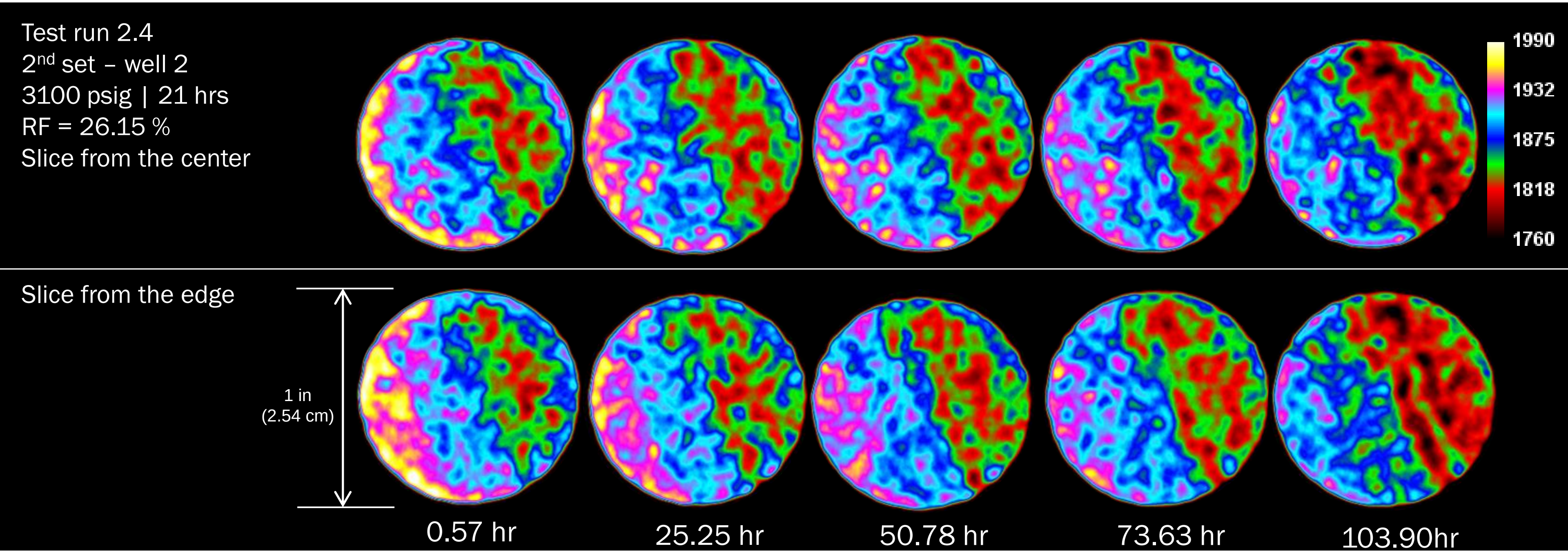
2. – Effluents was flashed at room conditions

3. – The produced oil is clearly lighter than the injected oil

4. – The oil produced from the Berea is heavier than the oil produced from the organic rich shale



CO_2
Compositional changes with time



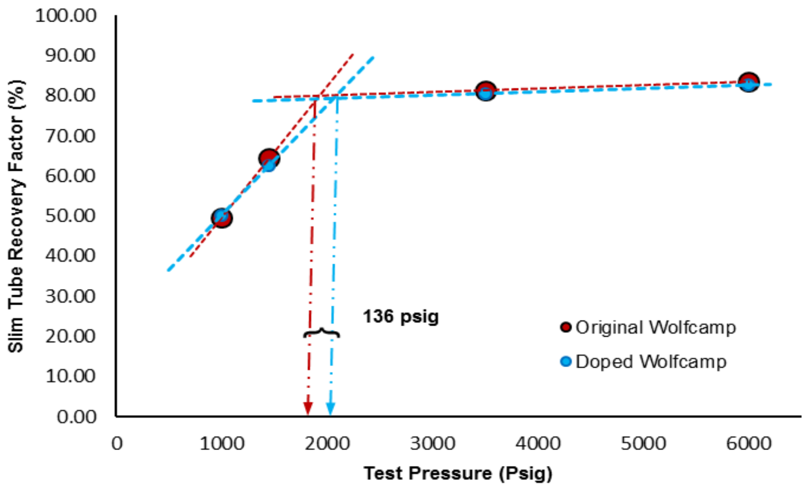
SPE-191752-MS

The Impact of MMP on Recovery Factor During CO_2 – EOR in Unconventional Liquid Reservoirs

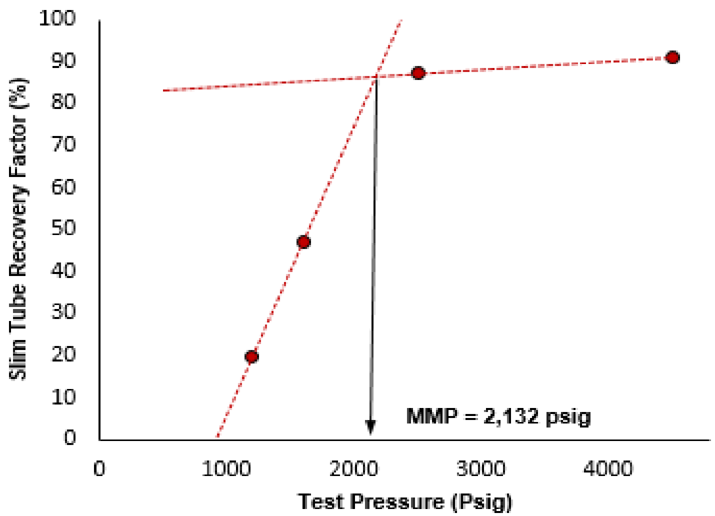
Imad A. Adel, Francisco D. Tovar, Fan Zhang, David S. Schechter,
Texas A&M University

Results and Discussions

Minimum Miscibility Pressure



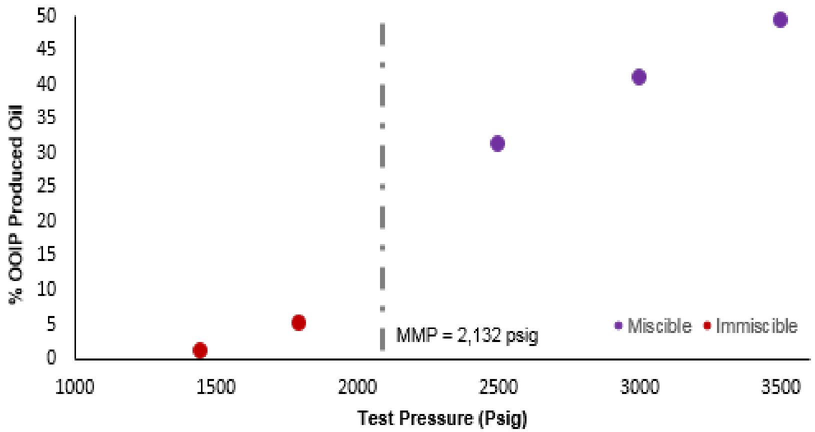
	Wofcamp		Eagle Ford
	Doped	Original	
MMP (psig)	2061	1925	2132



- The addition of iodobenzene does not cause a significant increase in the oil density either

Results and Discussions

Effect of pressure on recovery factor

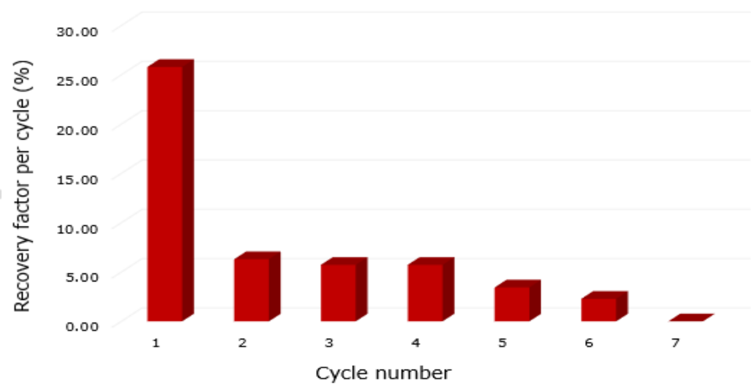


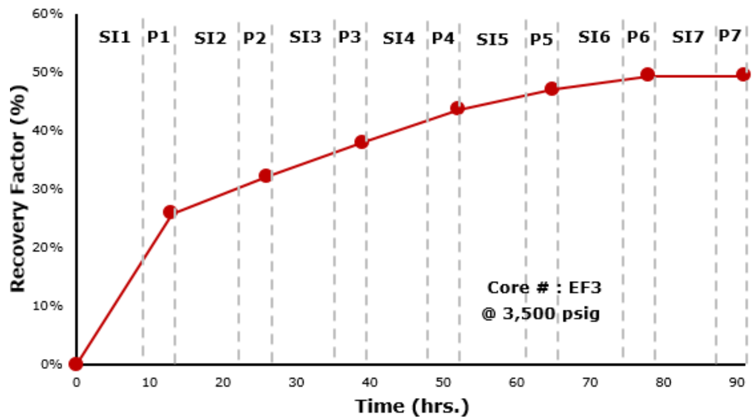
Miscibility Status	Test Pressure (psig)	Oil Recovery (% of OOIP)
Miscible	3500	49.31
	3000	40.9
	2500	31.03
Immiscible	1800	5.00
	1450	1.00
Res Temp (°F)	170	
MMP (psig)	2,132	

- Increasing pressure always leads to an increase in the recovery factor

Results and Discussions

Time-frame for recovery



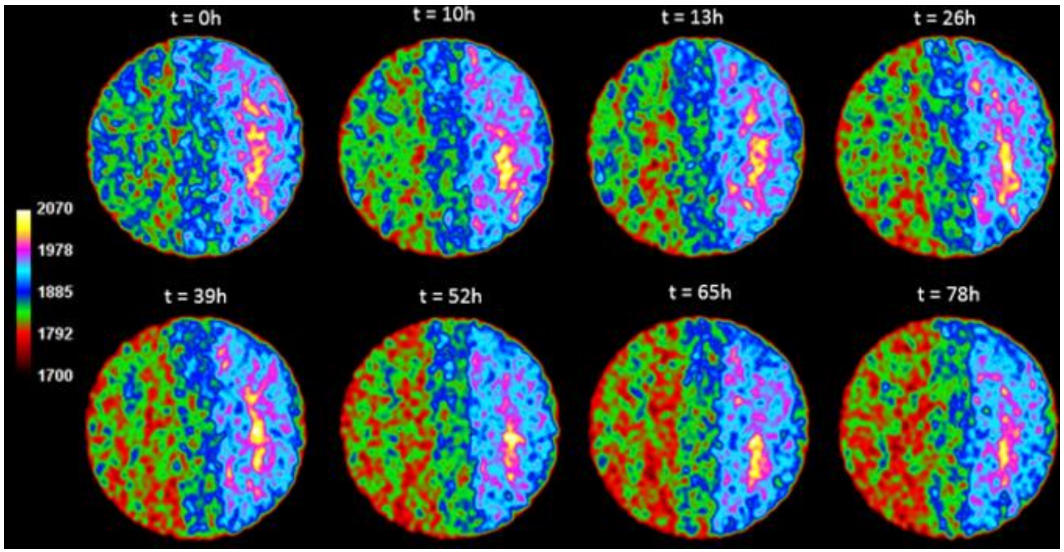


Recovery factor per cycle during CO_2 huff-and-puff experiment on core plug EF3 at 3,500 psig and soak time of 10 hours

- Most of the oil is recovered during the first cycle
- Similar results were observed in all the huff-and-puff experiments
- The oil recovery rate starts decreasing after the first cycle until it levels off as the maximum recovery is approached

Results and Discussions

CT-Scanning

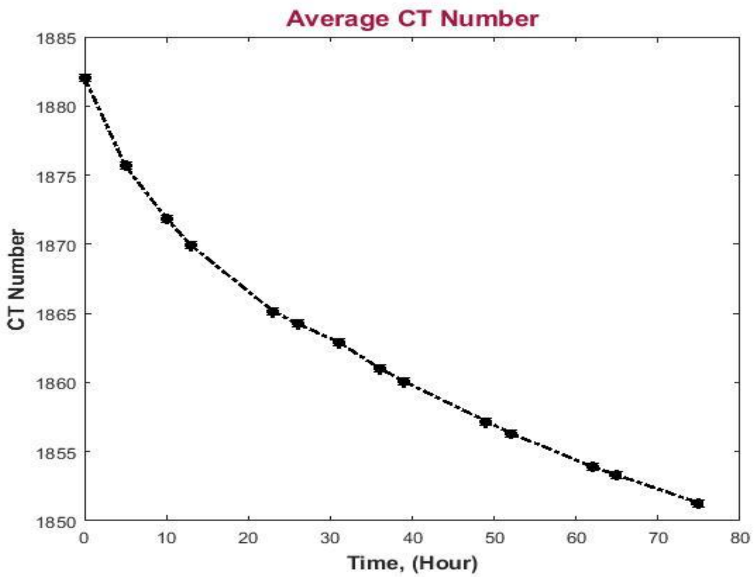


CT-scan images from the gas injection experiment of core EF3 at 3,500 psi

- CT-scans are performed regularly to track the changes in density as a function of time and space.
- The color on the left side changed from blue and green color to red, which means the density of that area decreased to a lower value
  - ➢ Evidence that CO_2 penetrate into the core plug and oil extracted out from the matrix

Results and Discussions

CT-Scanning

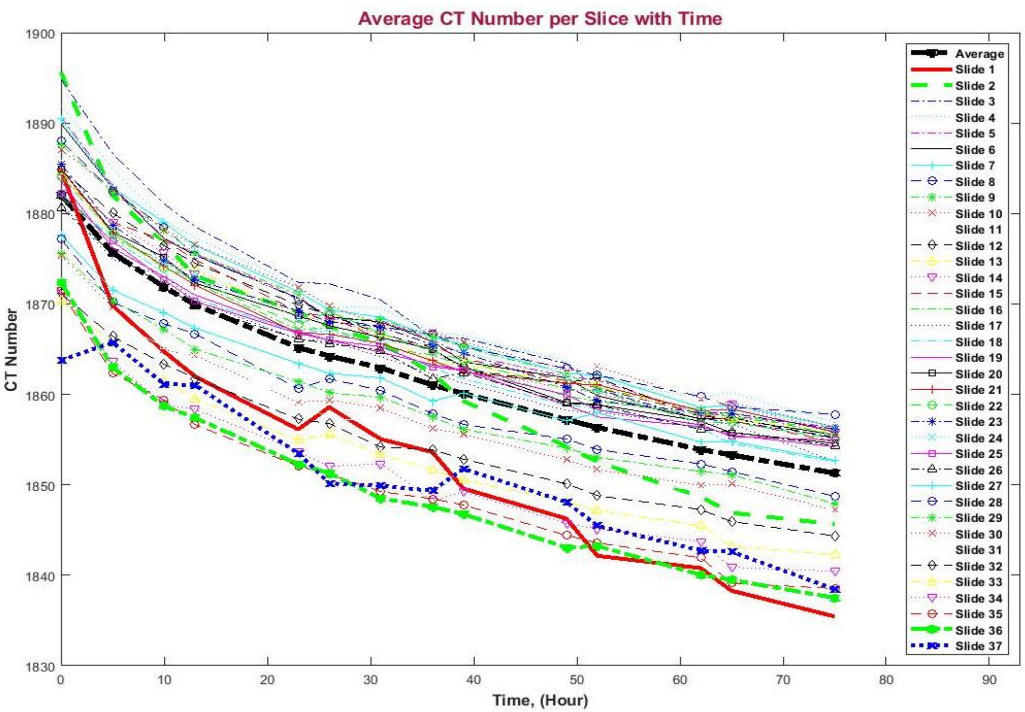


Average CT number for entire core plug during gas injection experiment at 3,500 psi

- The CT number of the doped oil is higher than the CT number of the CO_2 phase at all pressures:
  - This CT number decrease indicates that the oil was replaced by the CO_2 inside of the core
- The CT number of the doped oil is higher than the CT number of the CO_2 phase at all pressures

Results and Discussions

CT-Scanning

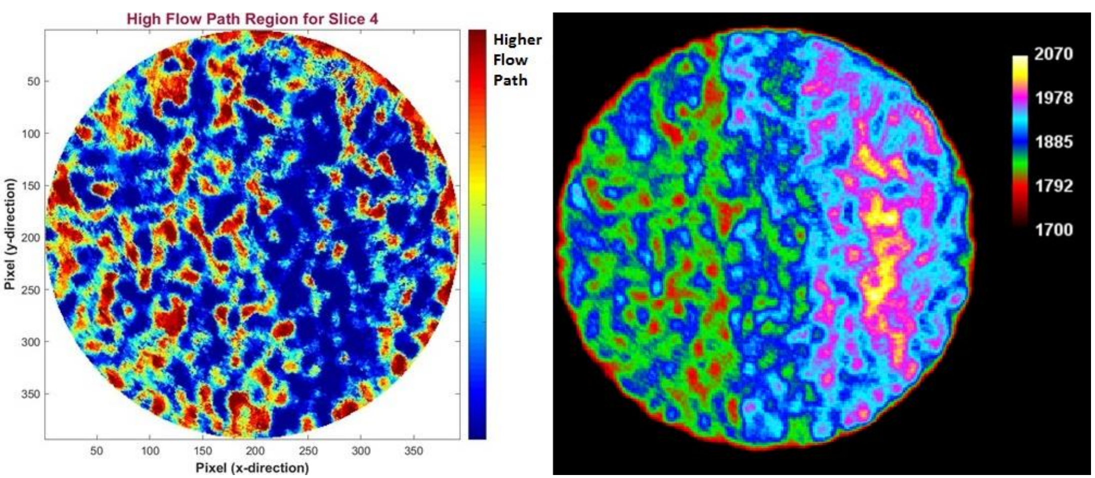


Average CT number for each slice during gas injection experiment at 3,500 psi

- The slices at both end of the core plug, have a more substantial CT number decreases during the experiment.
- The CT value of slices1 and 37 is lower than slices at the middle of the core:
    - CO_2 contacts a larger area per slice at the edges of the cores, Hence a larger decrease in CT values.

Results and Discussions

CT-Scanning – Flow path



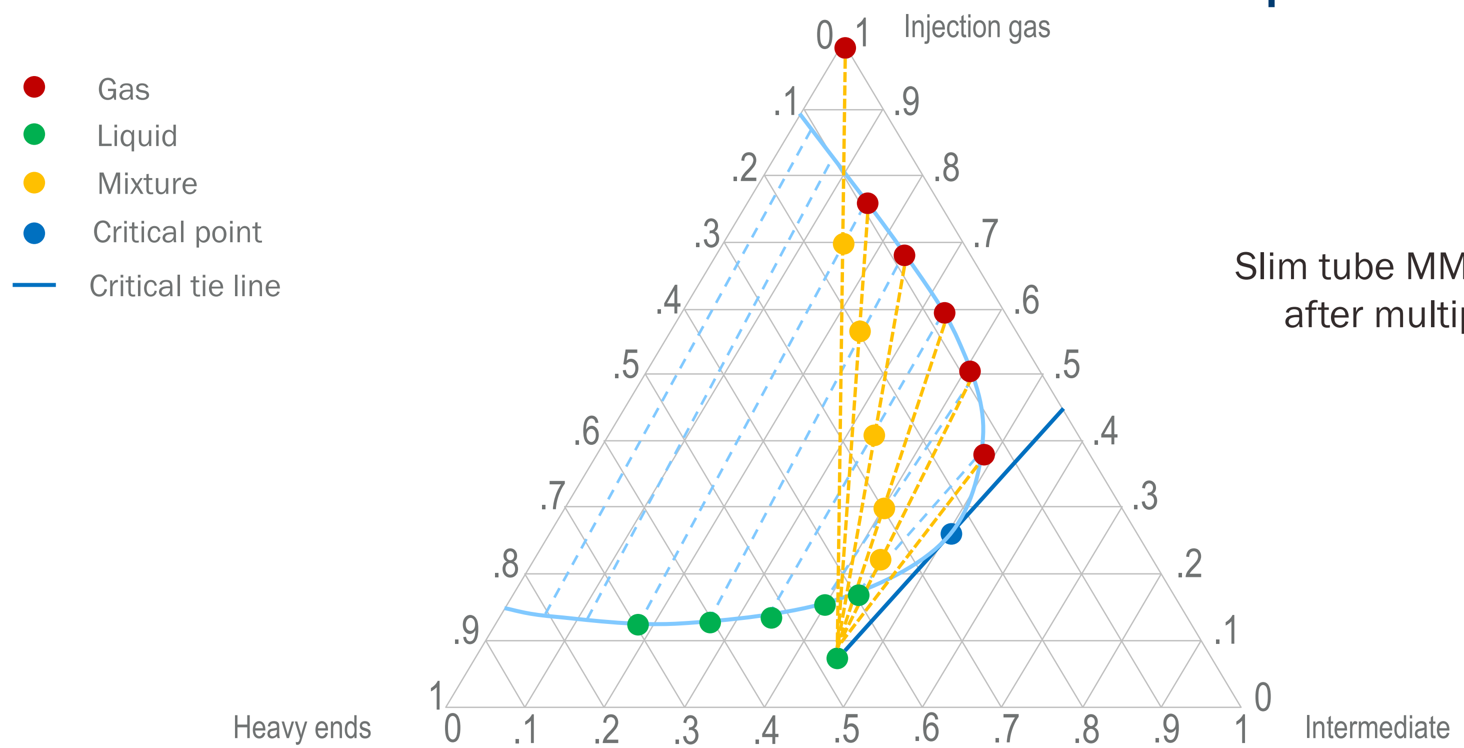
High flow path region from the experiment at 3,500 psi for slices 4 and corresponding CT image before the experiment

The pixels for delta CT number above 50 HU were marked as 1

We counted the number of times high CT number were shown for each pixel during the gas injection experiment

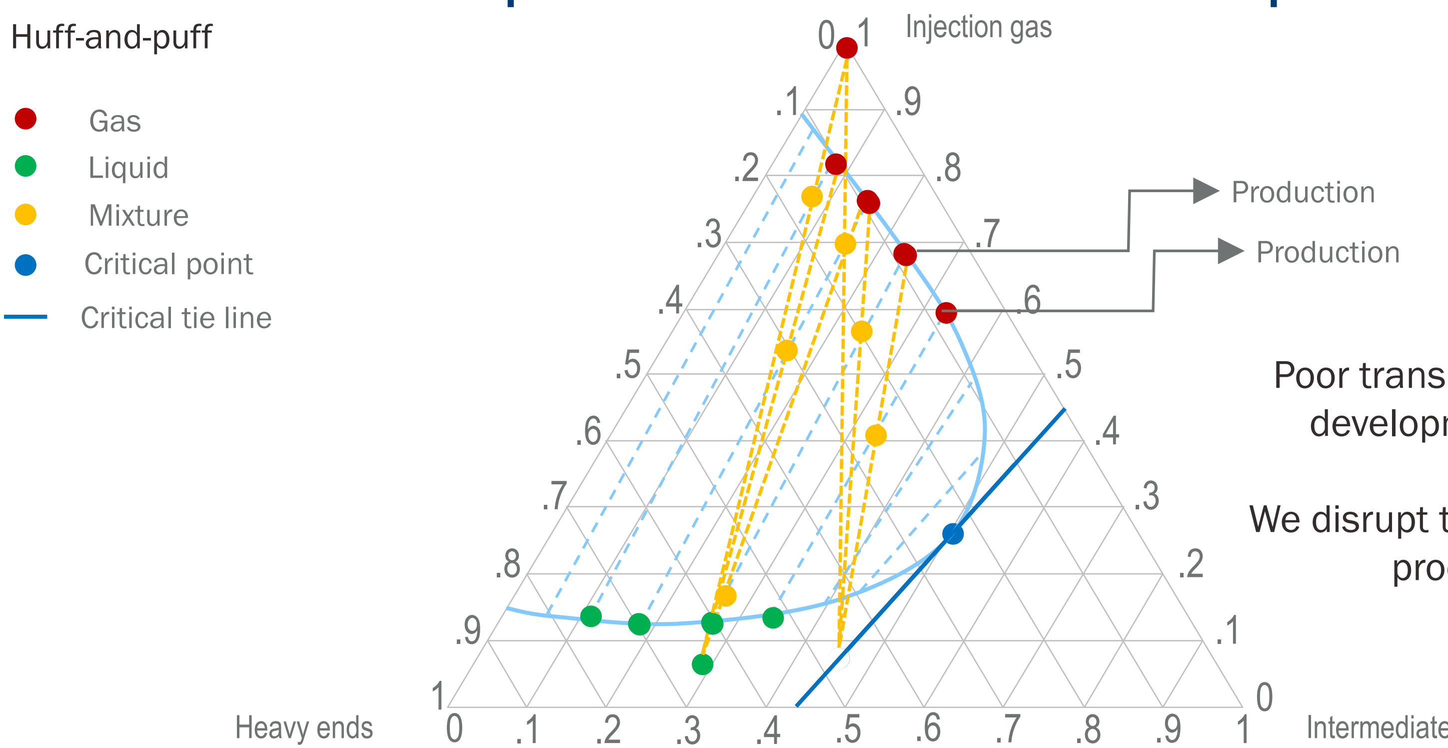
- The high flow path region can be generated and used to deterermine the parameters of the core-scale simulation model

Vaporizing gas drive



Slim tube MMP is developed after multiple contacts

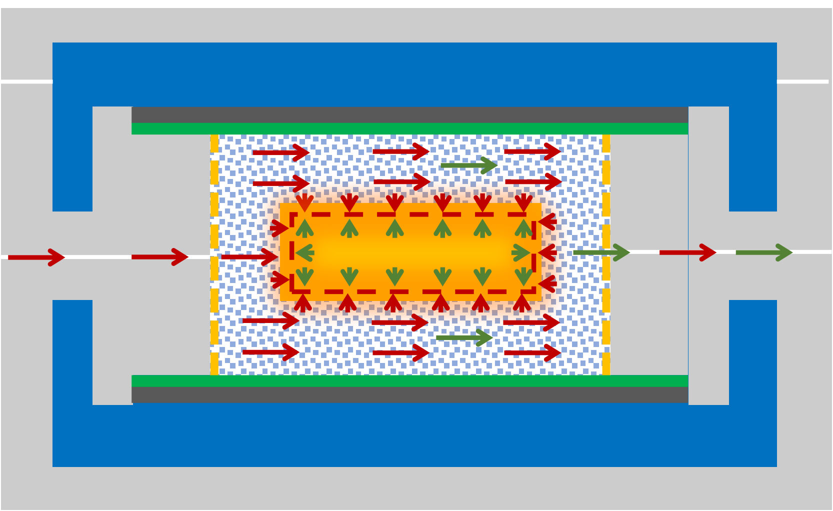
Peripheral slow-kinetics vaporizing gas drive

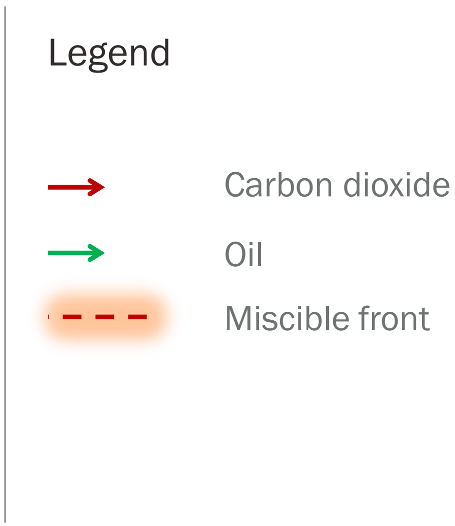


Poor transport slows down the development of miscibility

We disrupt the process with each production cycle

Peripheral slow-kinetics vaporizing gas drive

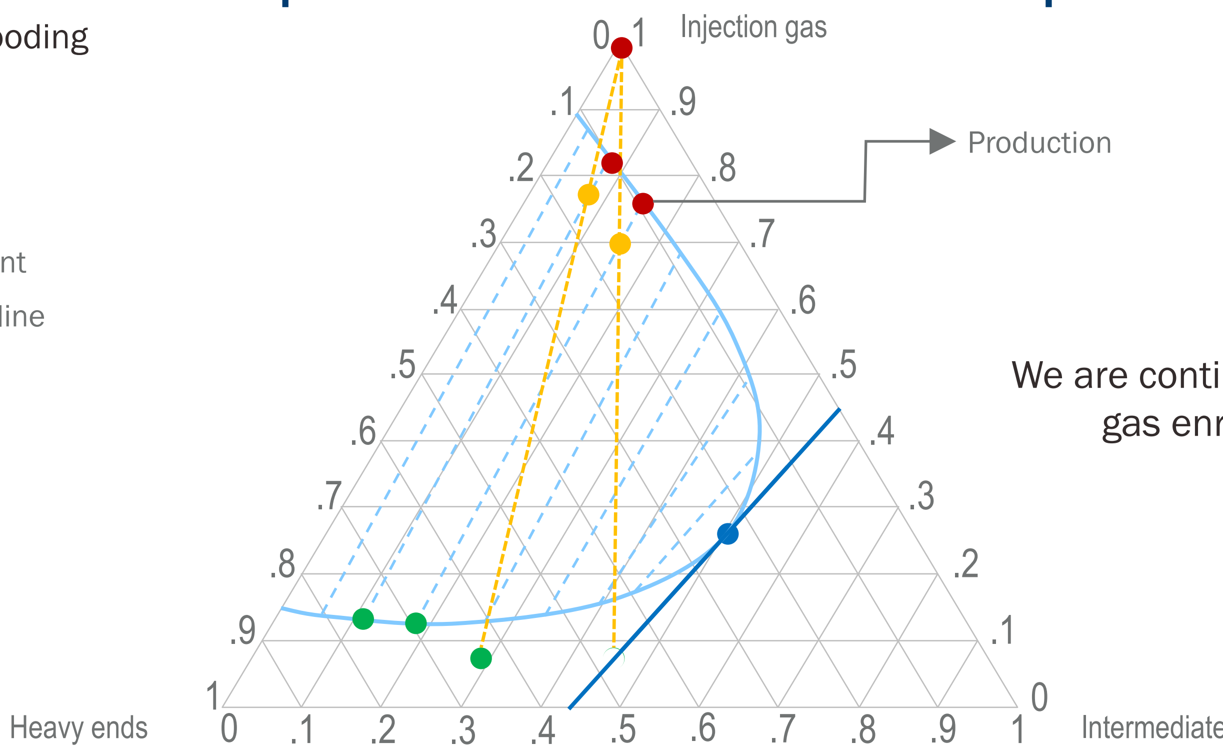




Peripheral slow-kinetics vaporizing gas drive

Continuous flooding

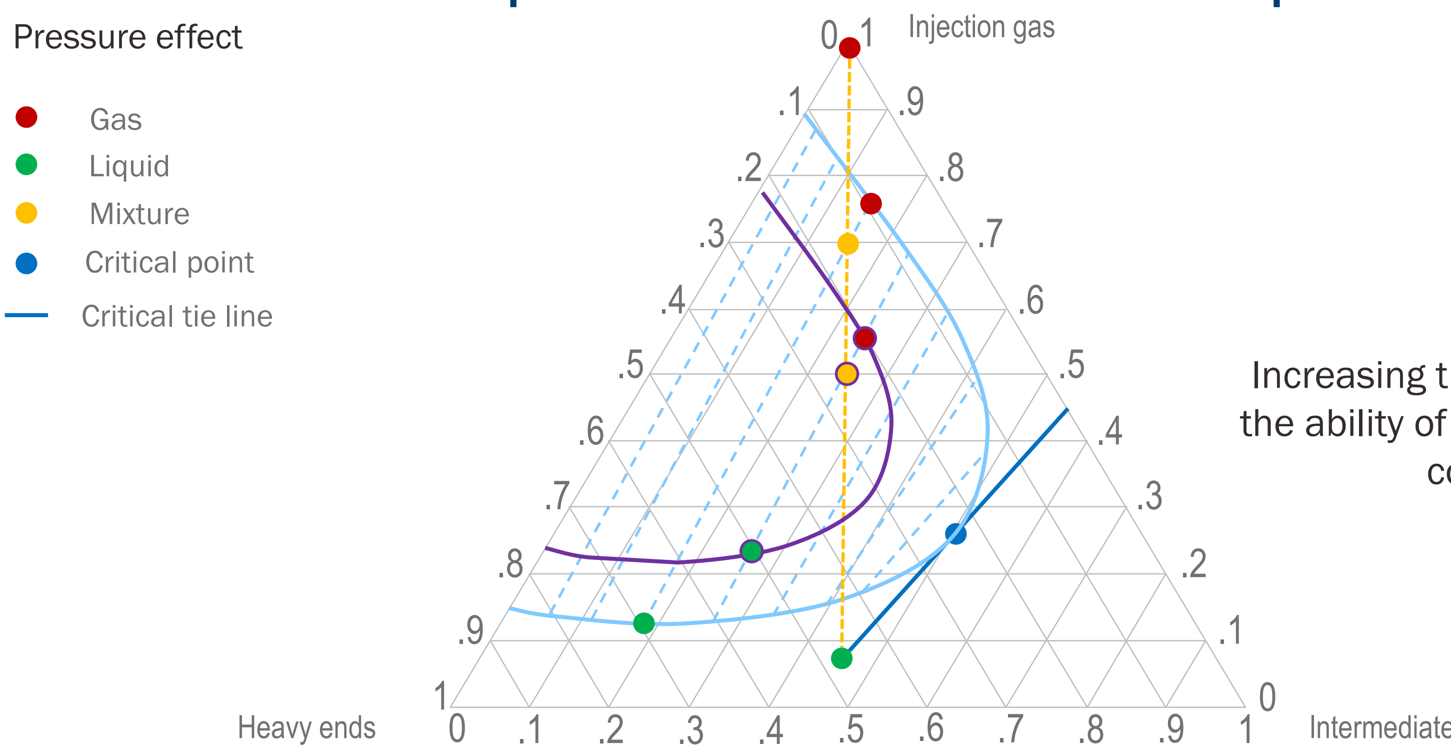
- Gas
- Liquid
- Mixture
- Critical point
- Critical tie line



We are continuously disrupting the gas enrichment process

Peripheral slow-kinetics vaporizing gas drive

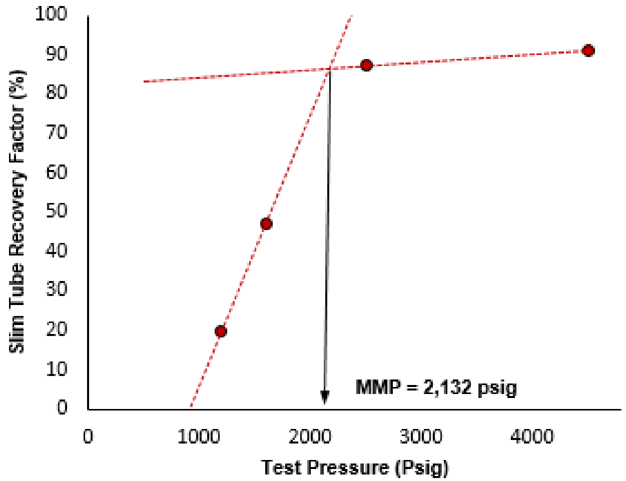
Pressure effect



Increasing the pressure improves the ability of the gas to strip out oil components

Minimum Miscibility Pressure (MMP) for Eagle Ford Oil

- The MMP was measured using the slim tube technique using an 80-ft coil
- The MMP was determined to be 2,132 psi.

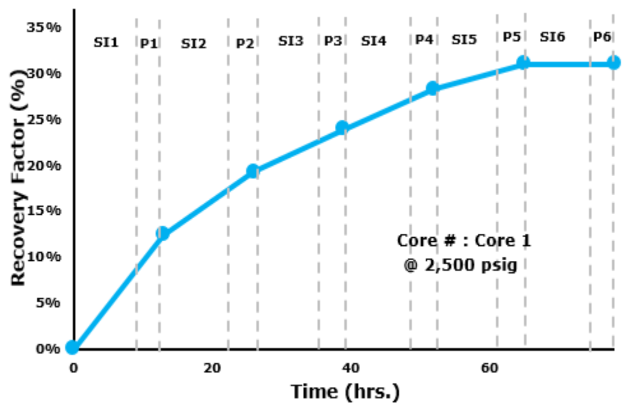


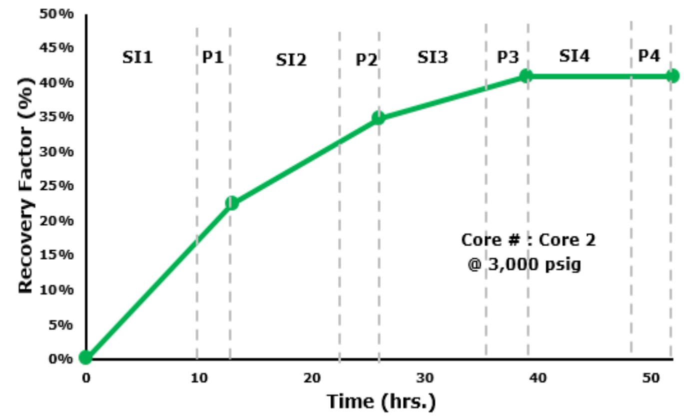
	Doped Eagle Ford Crude Oil	
Miscibility Status	Test Pressure (psig)	Oil Recovery (% of OOIP)
Miscible	4500	91.3
Miscible	2500	87.24
Immiscible	1600	47.23
Immiscible	1200	19.62

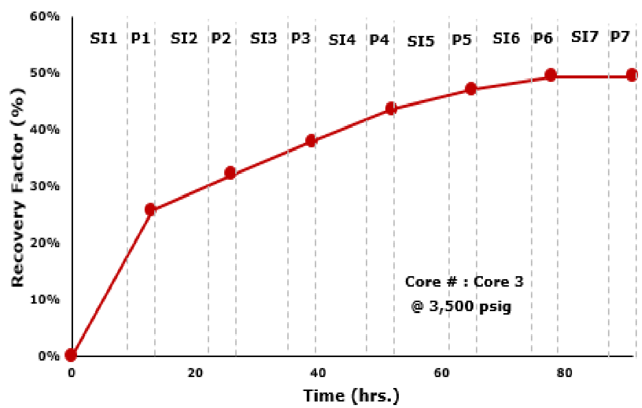
Res Temp (°F)	170
MMP (psig)	2,132

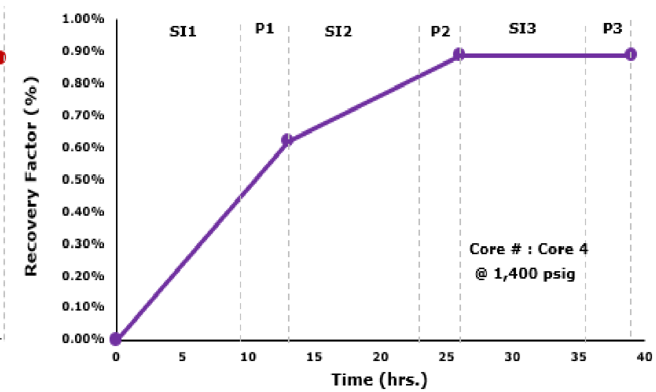
Results of Gas Injection Experiments

- The recovery factors increases as the pressure increases.
- The maximum RF is 49% of OOIP at 3,500 psi.
- RF is less than 5% when pressure below MMP.



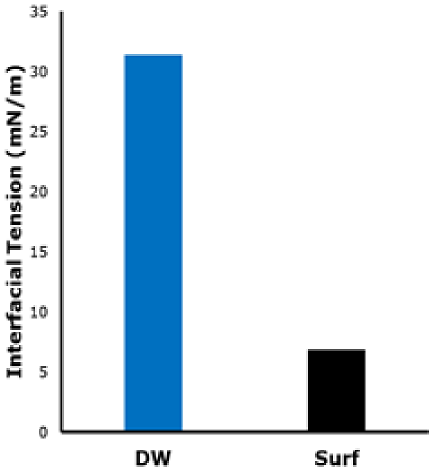


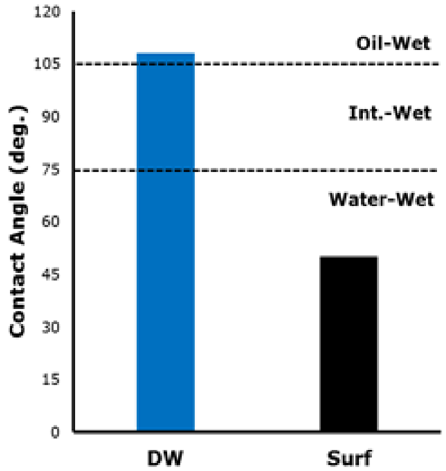


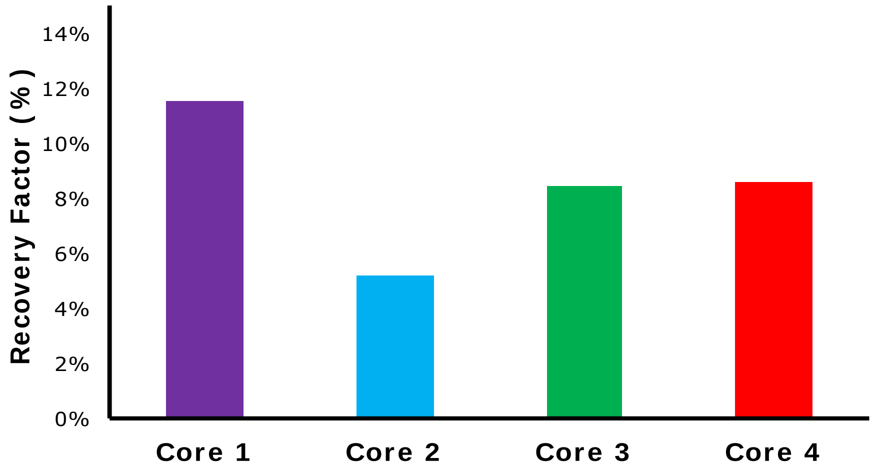


SPE-191502-MS • Enhanced Oil Recovery in Unconventional Liquid Reservoir Using a Combination of CO2 Huff-n-Puff and Surfactant-Assisted Spontaneous Imbibition • Fan Zhang

Results of SASI Related Experiments







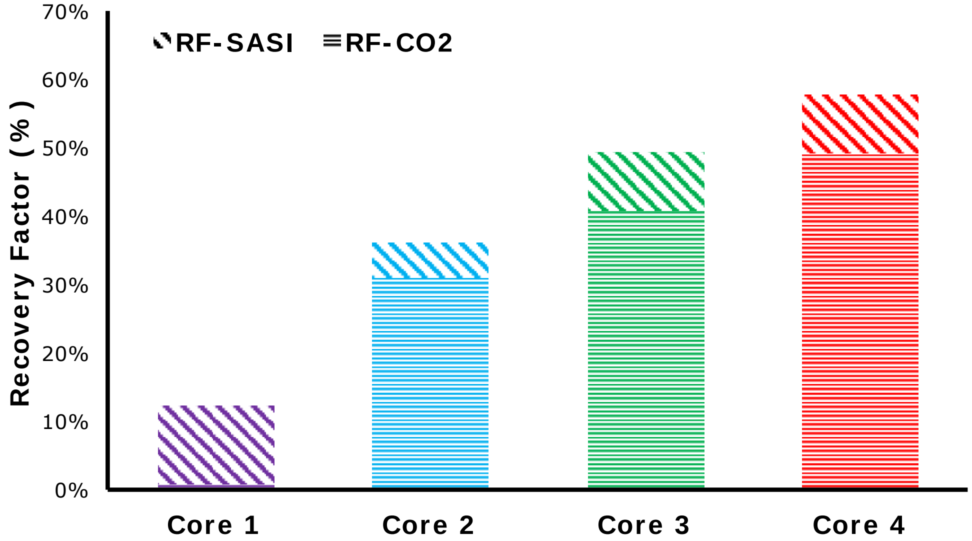
- Surfactants lead to wettability alteration and IFT reduction.
- Up to an extra 12% of oil recovered through spontaneous imbibition experiments

Observation during SASI

SASI at 12 hours SASI at 240 hours

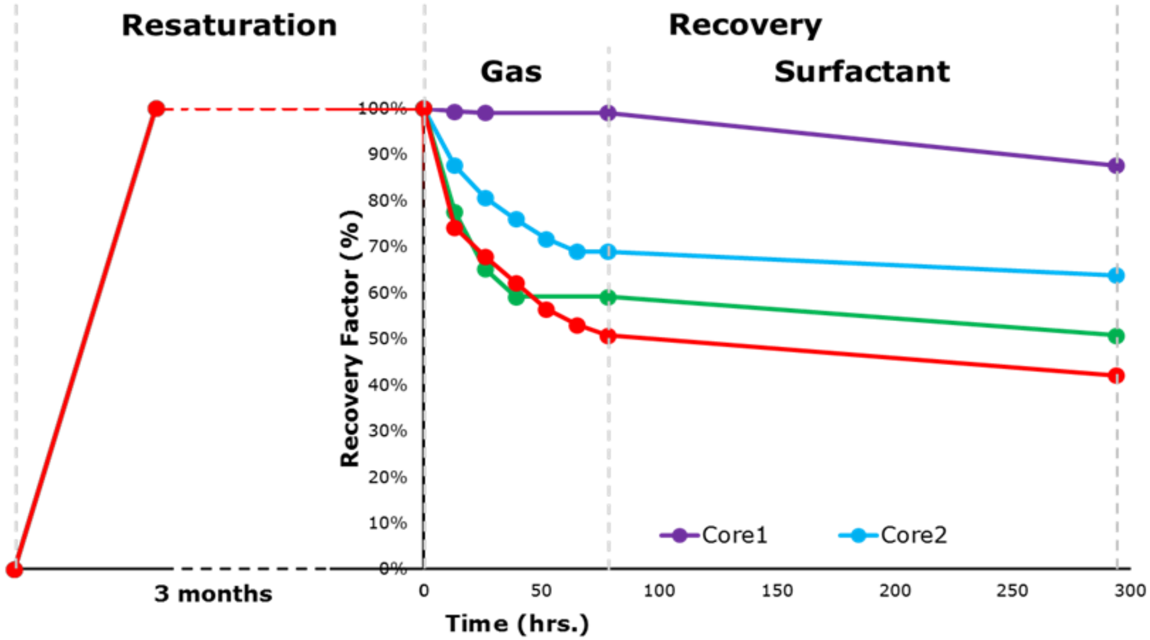
- At the beginning of SASI, foam was collected at the top cylinder.
- CO_2 existed inside the core plugs after gas injection experiments.
- Even though 49% of OOIP produced from gas injection experiment, additional oil can be recovered from SASI.

Recovery Factor of Hybrid EOR Experiments



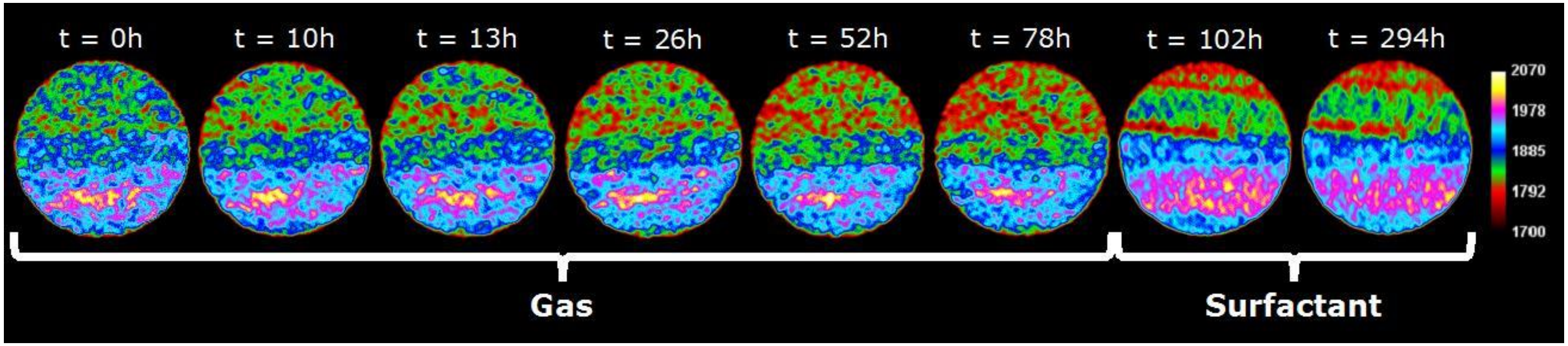
- Up to 49% of OOIP was produced from CO_2 huff-n-puff experiments.
- The maximum recovery factor of hybrid EOR experiments is 58% of OOIP.

Experimental Timeline



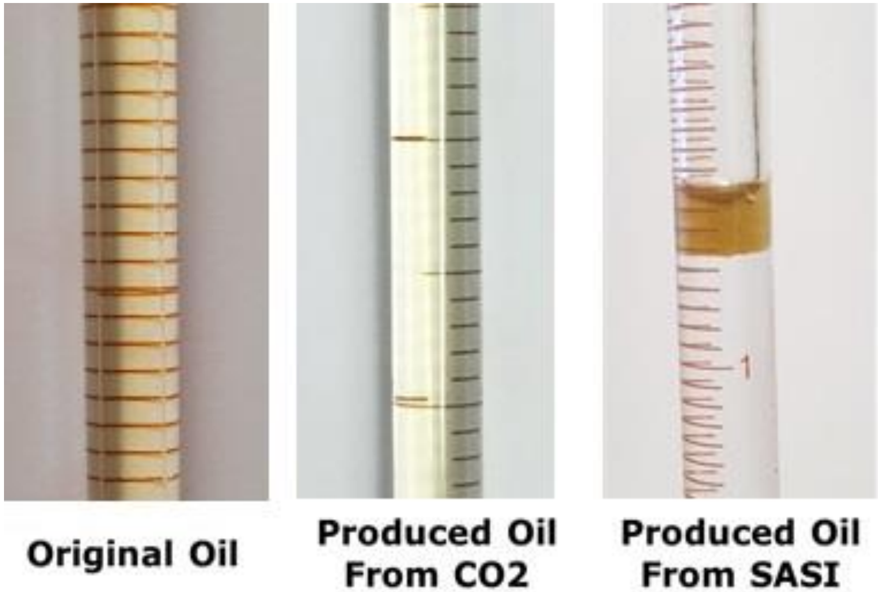
- Three months of re-saturation and aging process.
- Recovering up to 58% of the OOIP in only 12 days.

CT-Scan Images from Gas Injection and Imbibition Experiments



- Gas injection experiments: more oil recovered from low CT number region (larger pores).
- SASI: most of oil produced from high CT number region (smaller pores).

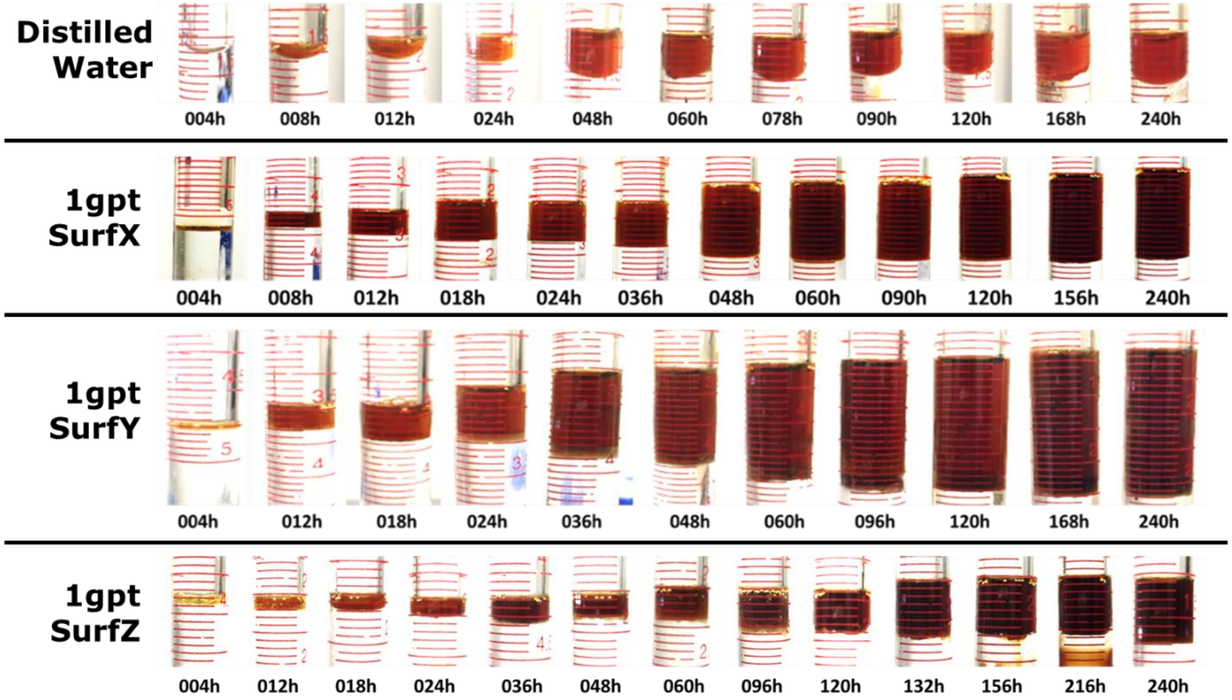
Color Change of Produced Oil



- Lighter and intermediate components of the oil are recovered during the CO_2 huff-n-puff experiments.
- Heavier components are recovered during the SASI.

Color Change of Oil during Spontaneous Imbibition Experiments

- The color of the produced oil changed from lighter to darker.
- Lighter components of oil are recovered within the first 24 h.
- A large fraction of the oil produced from the SASI is coming from the smaller pores.



Low IFT Imbibition and Drainage

Dr. David S. Schechter

Texas A&M University

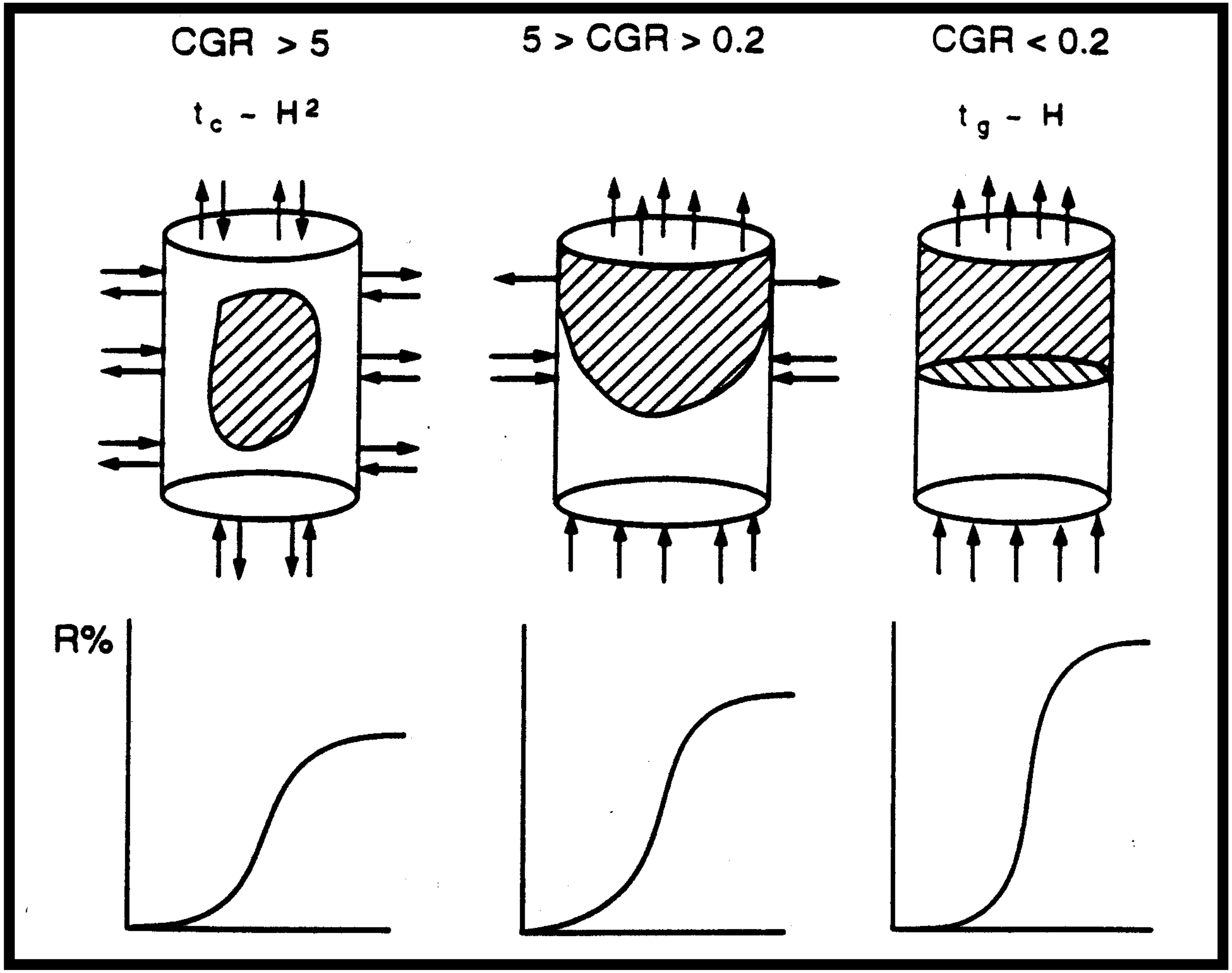
Low IFT Imbibition and Drainage:

$\boxed{\textbf{Gravity Dominates at Low IFT}}$

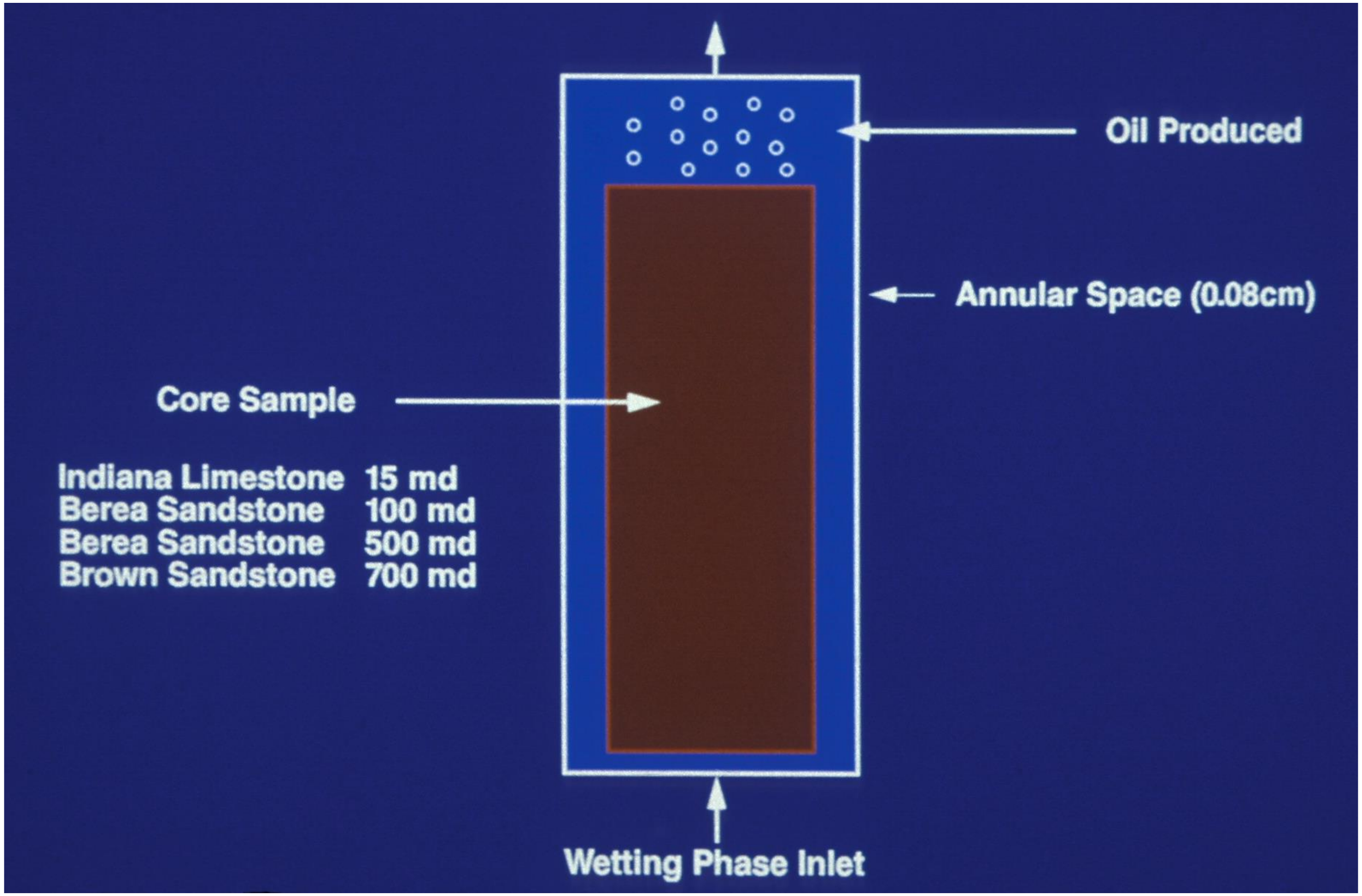
Imbibition: Mechanisms and Recovery

Imbibition Mechanisms

Imbibition Recovery



Capillary Imbibition Cell



Imbibition Rate Theory

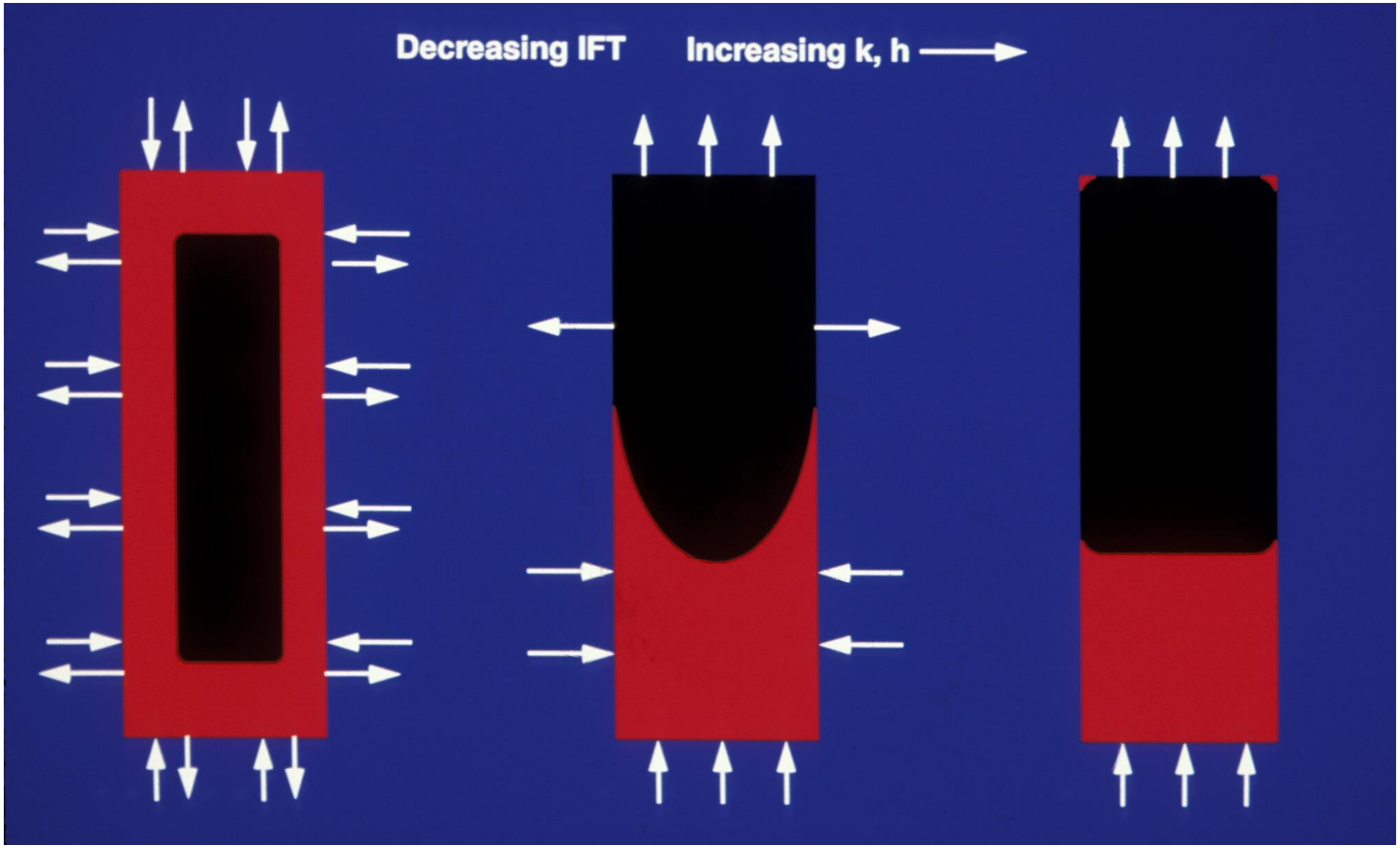
$$\boxed{t_d = t\sqrt{\frac{k}{\phi}\frac{\sigma\cos\theta}{\mu_w L^2}}}$$

Correlation of IFT and $\Delta\rho$

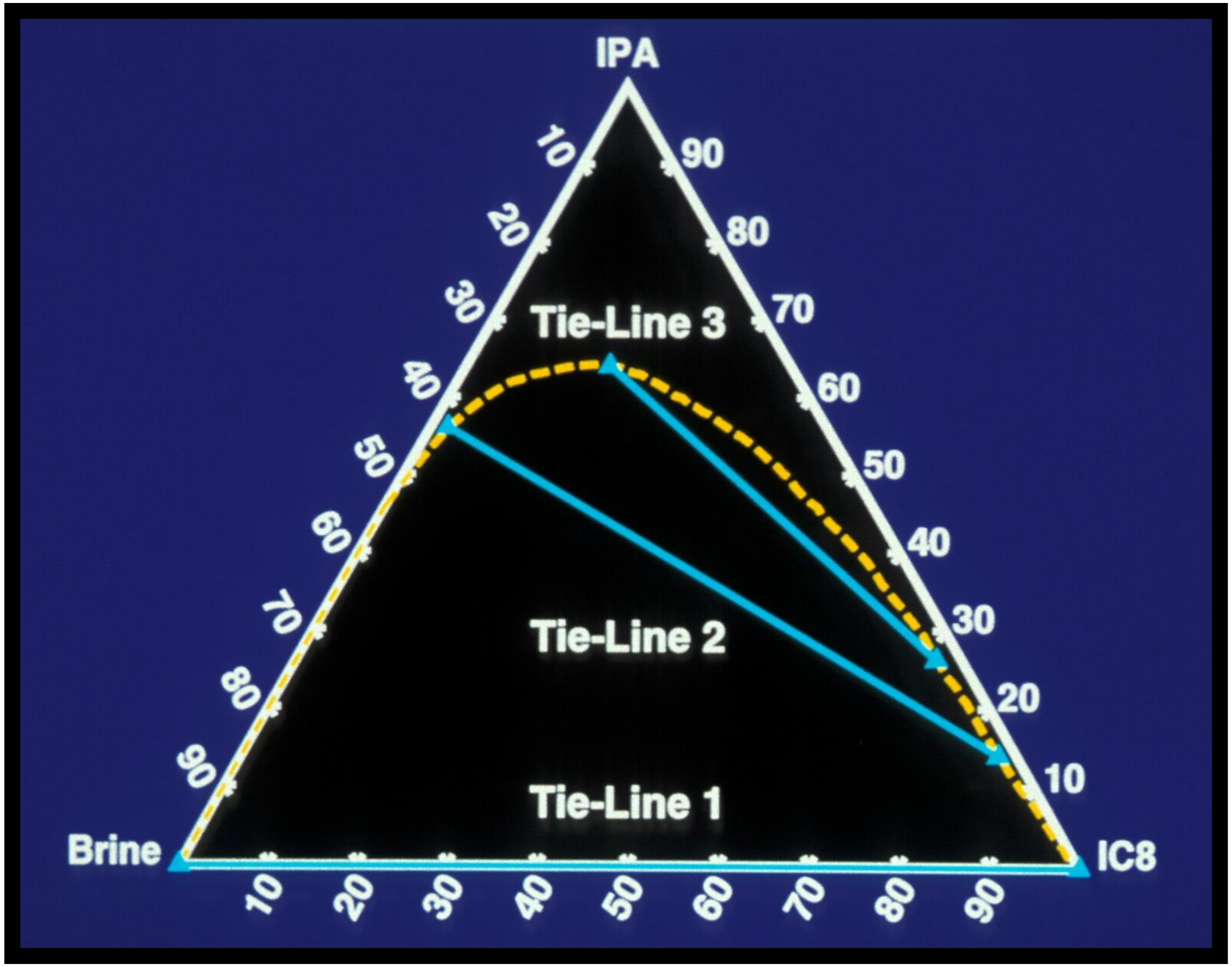
$$\sigma = \sigma \times \left[\frac{\Delta\rho}{\Delta\rho^{*}} \right]^{\frac{\gamma}{\beta}}$$

$$\frac{\gamma}{\beta} \cong 3.8$$

Capillary and Gravity Imbibition



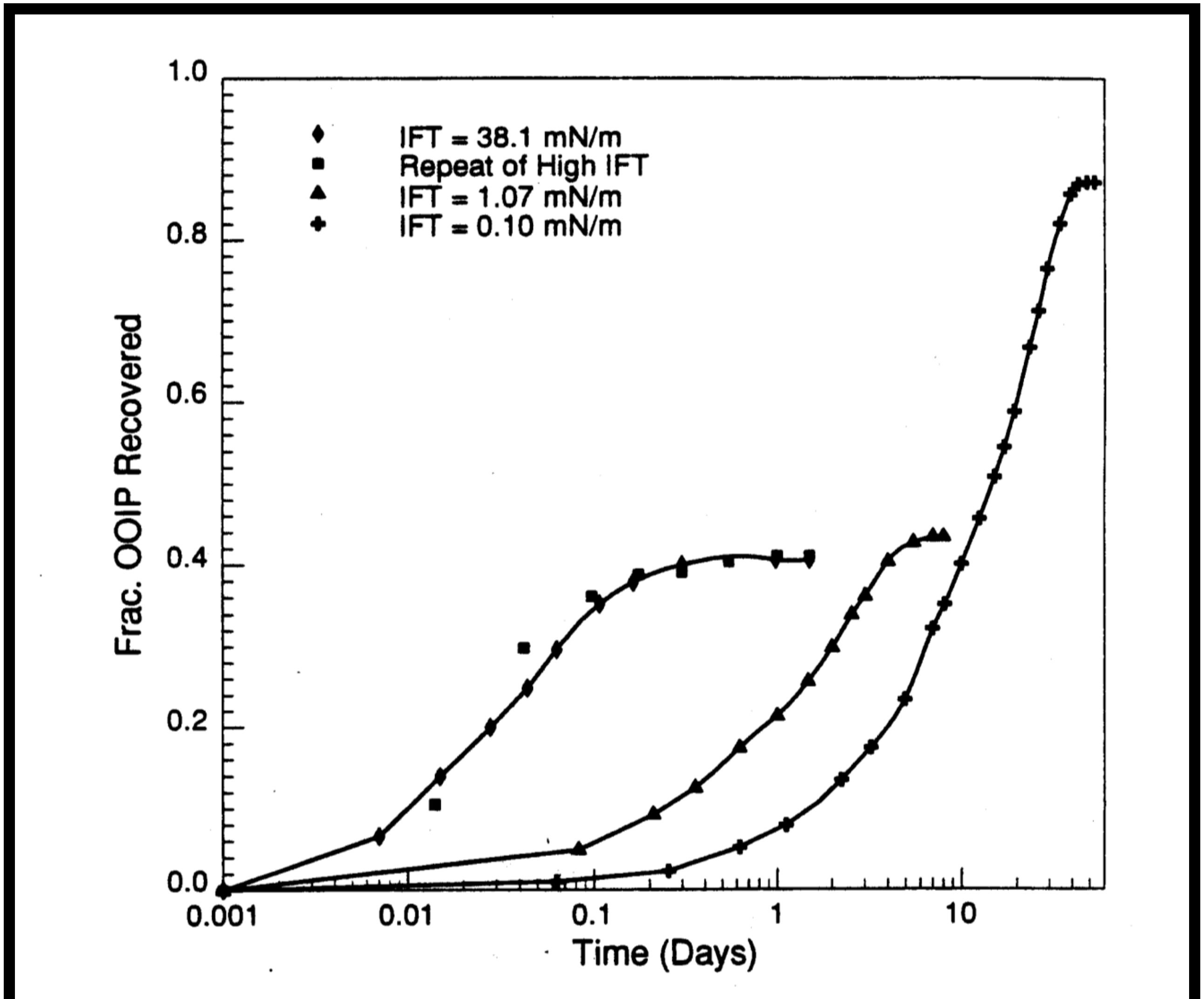
Phase Diagram for Brine/IC8/IPA System



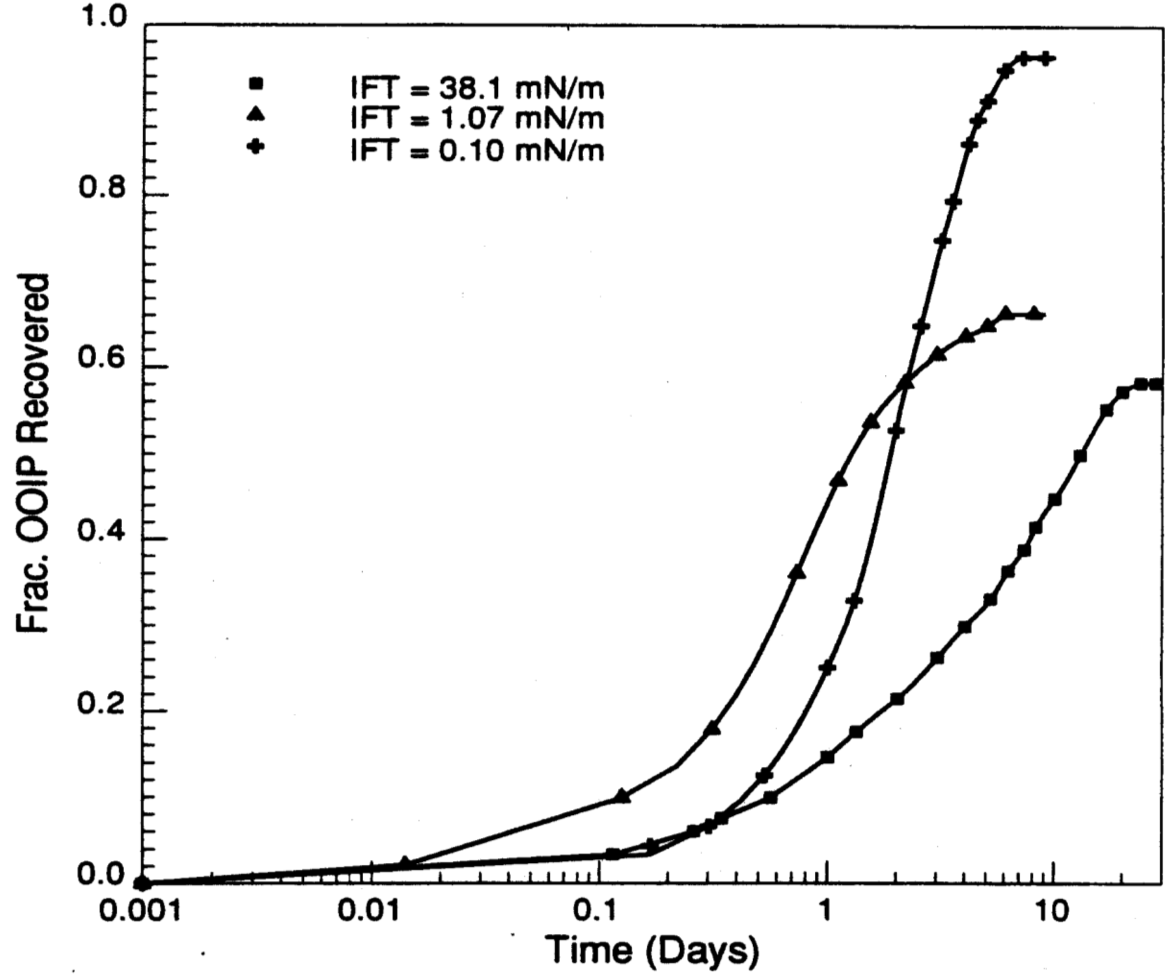
Phase Behavior Data

Tie Line	$\Delta\rho$ (g/cc)	IFT (mN/m)
1	0.33	38.1
2	0.21	1.07
3	0.11	0.10

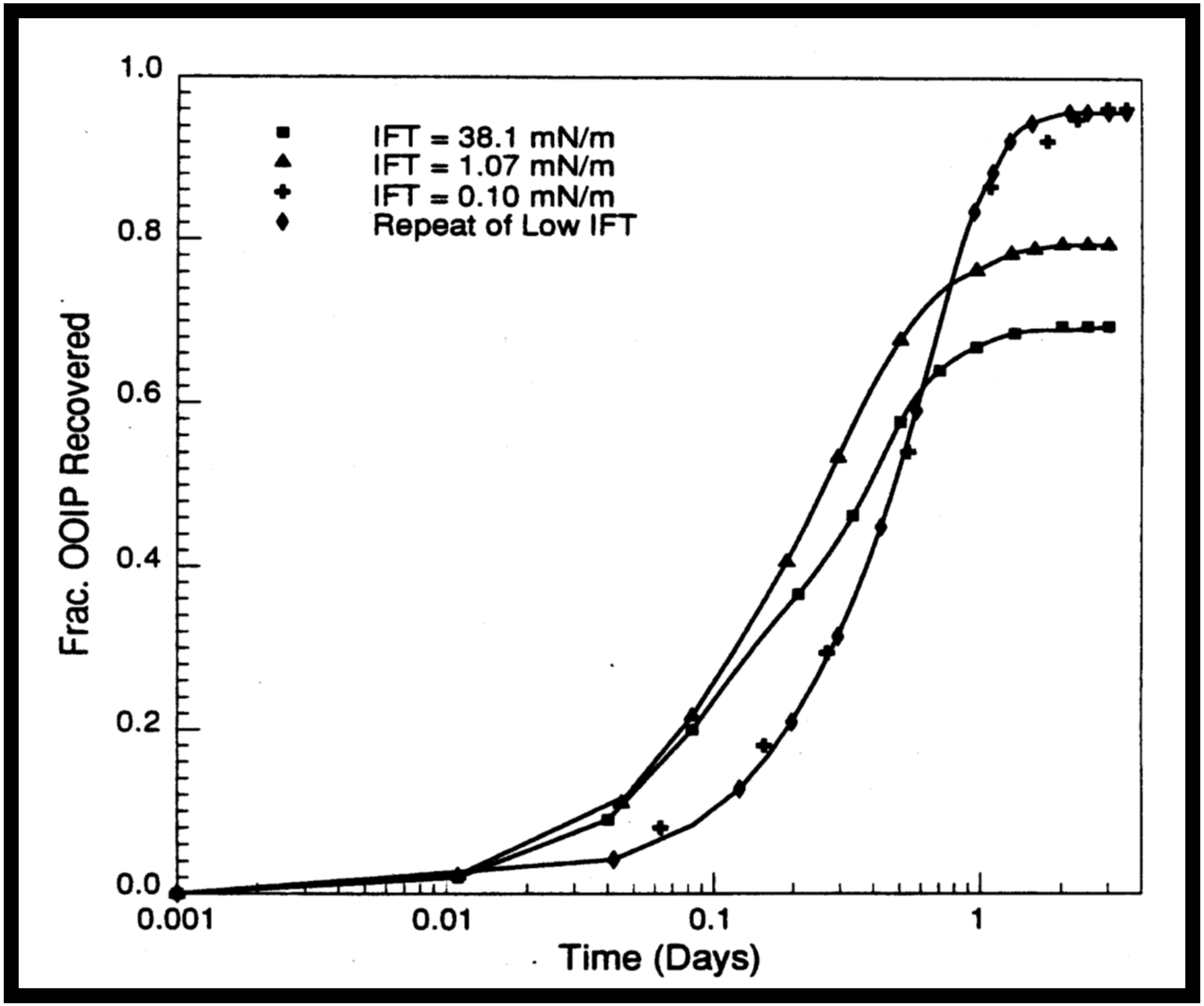
Imbibition in 15 md Limestone



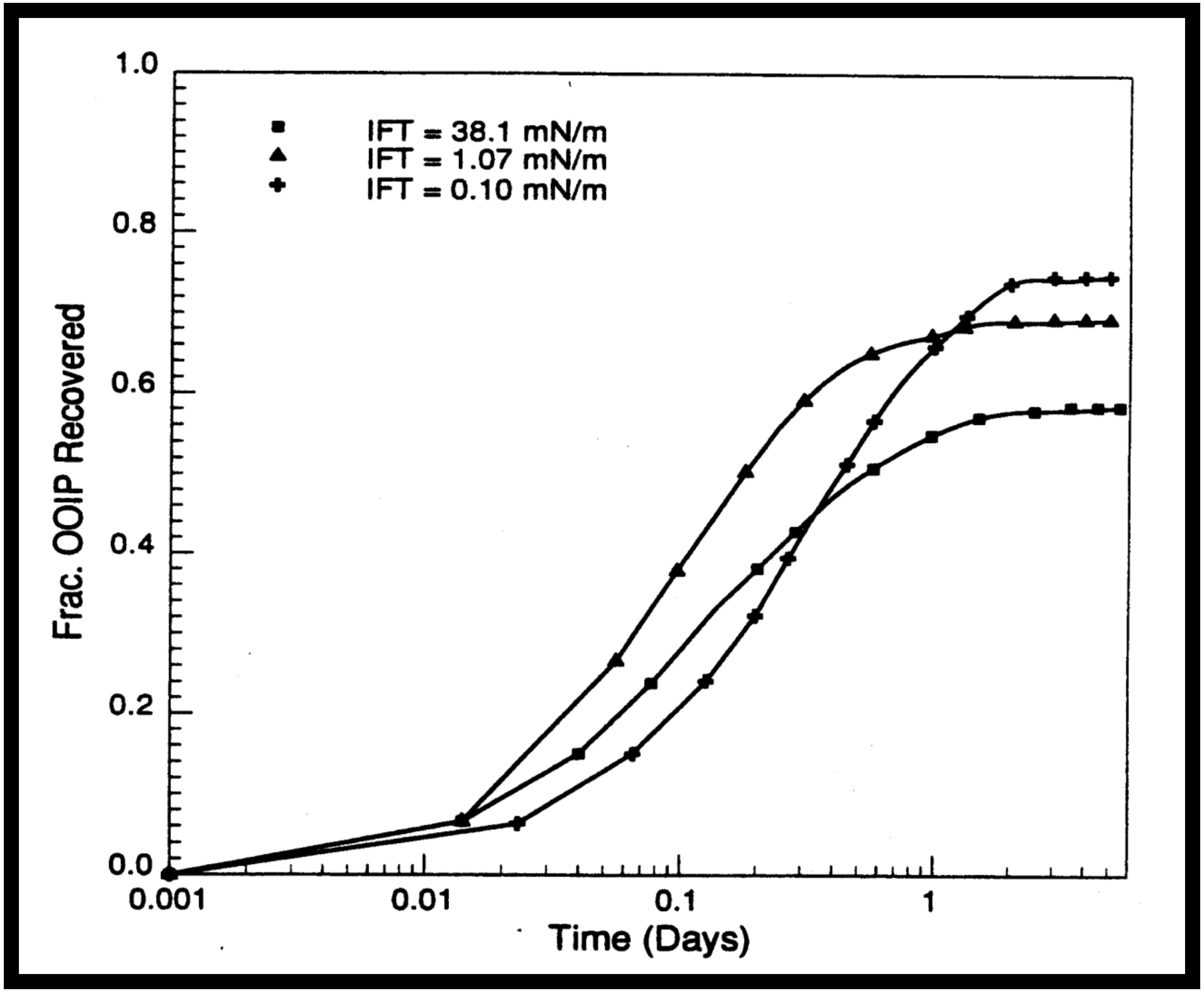
Imbibition in 100 md Berea



Imbibition in 500 md Berea



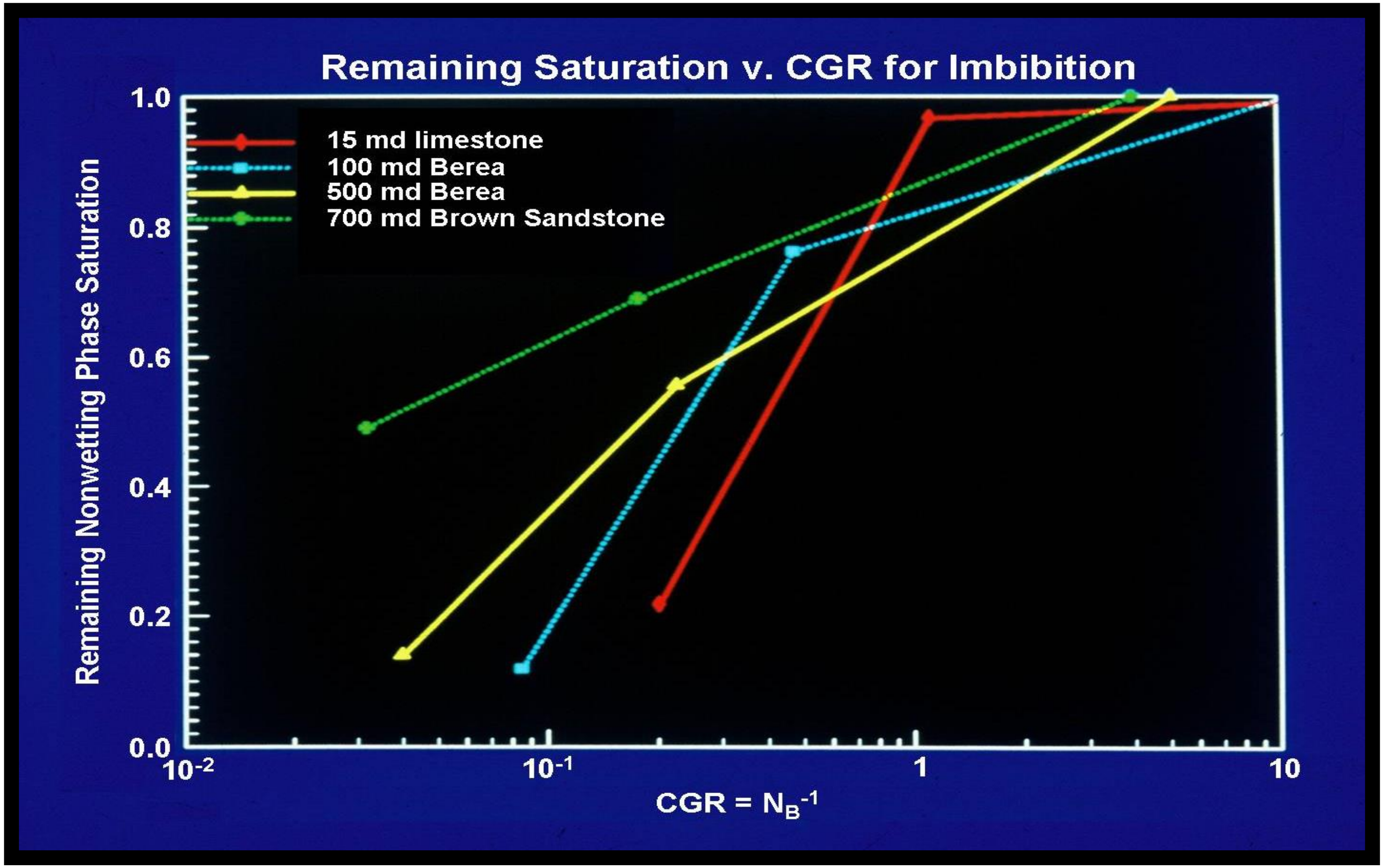
Imbibition in 700 md Brown Sandstone



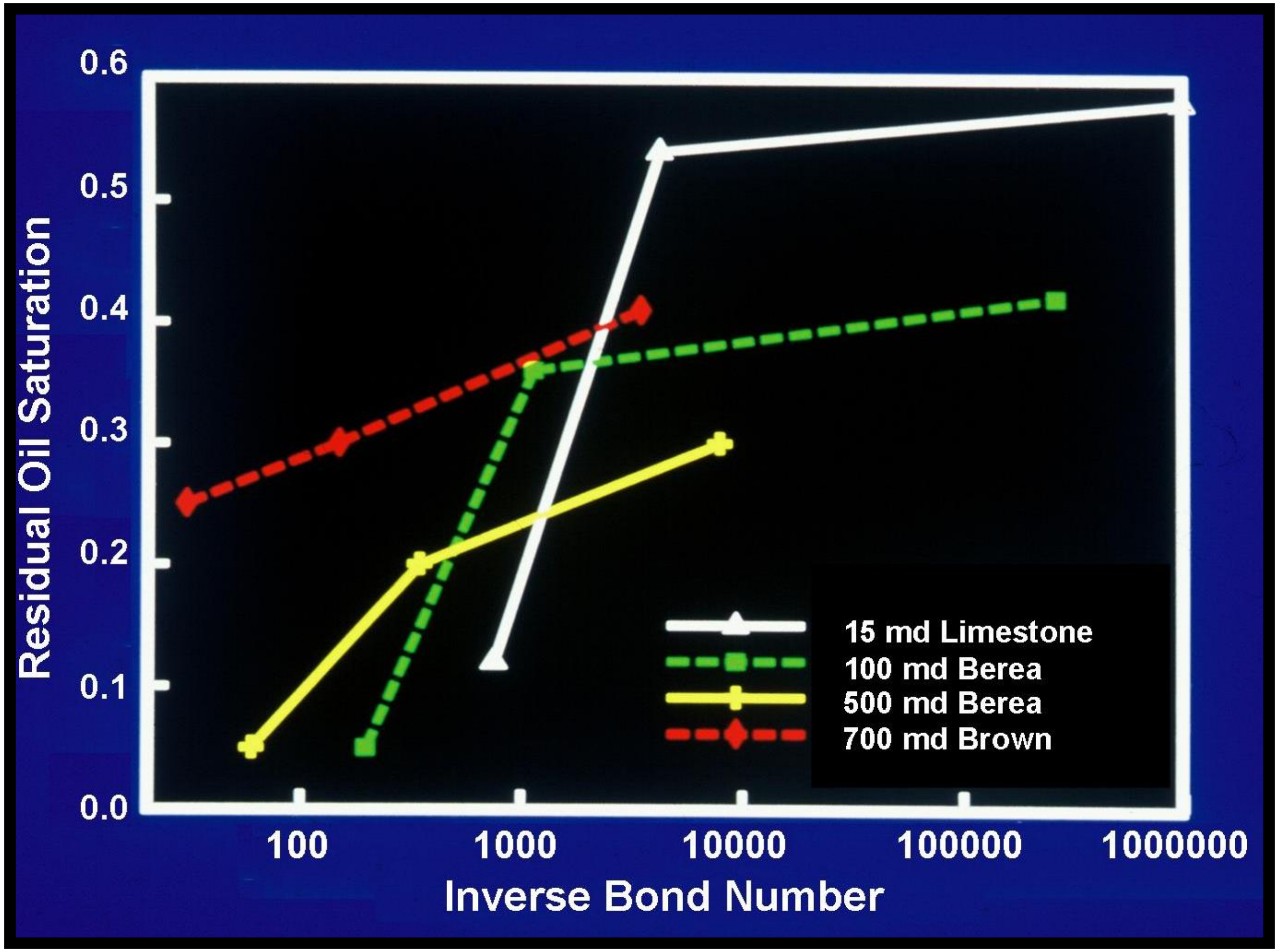
Bond Number

$$\boxed{N_B = \sqrt{\frac{K}{\phi}}\ \frac{\sigma\cos\theta}{\Delta\rho g h}}$$

Remaining Saturation vs. CGR for Imbibition



Remaining Oil Saturations at Different IFTs

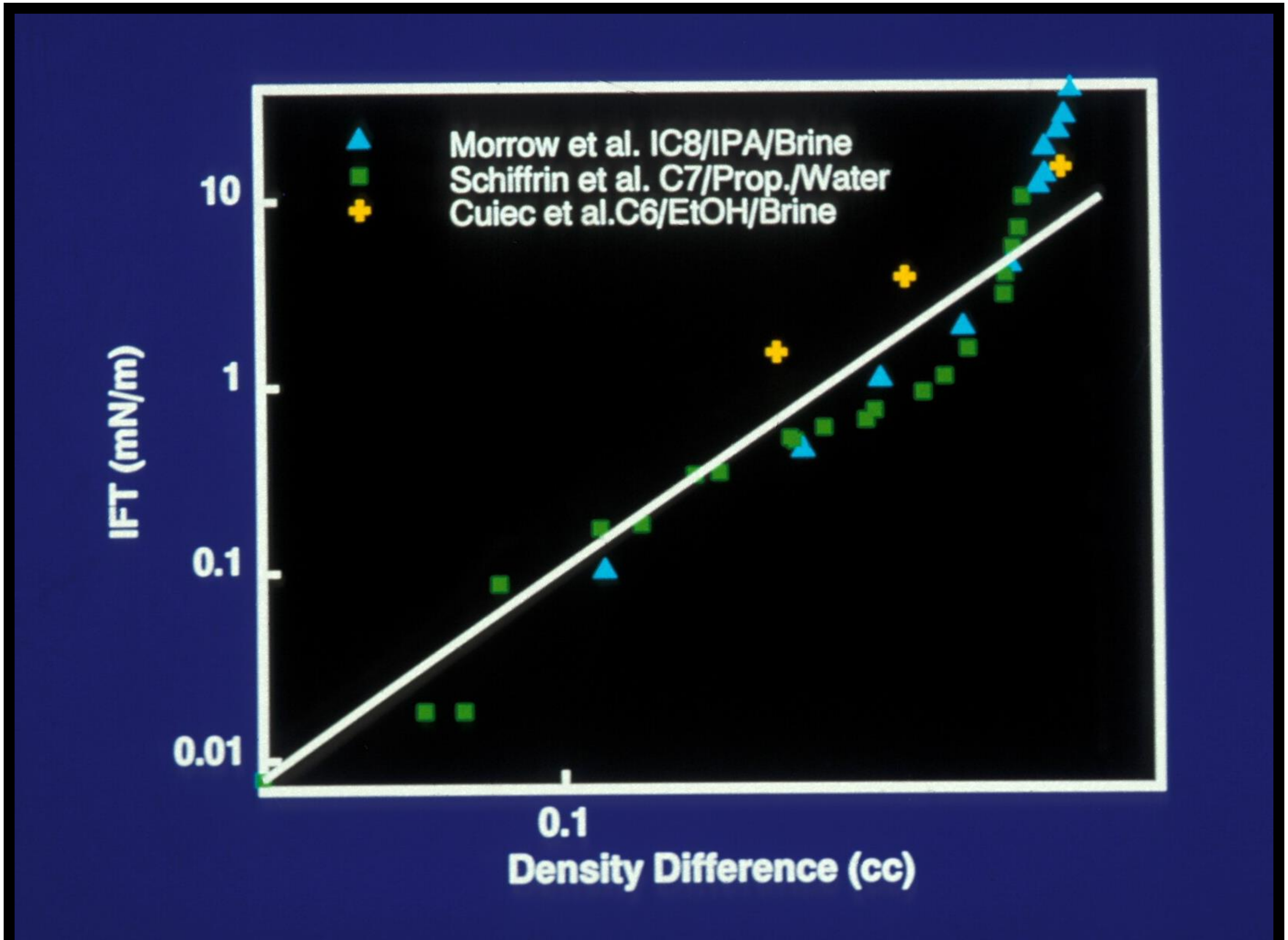


Critical Scaling Theory

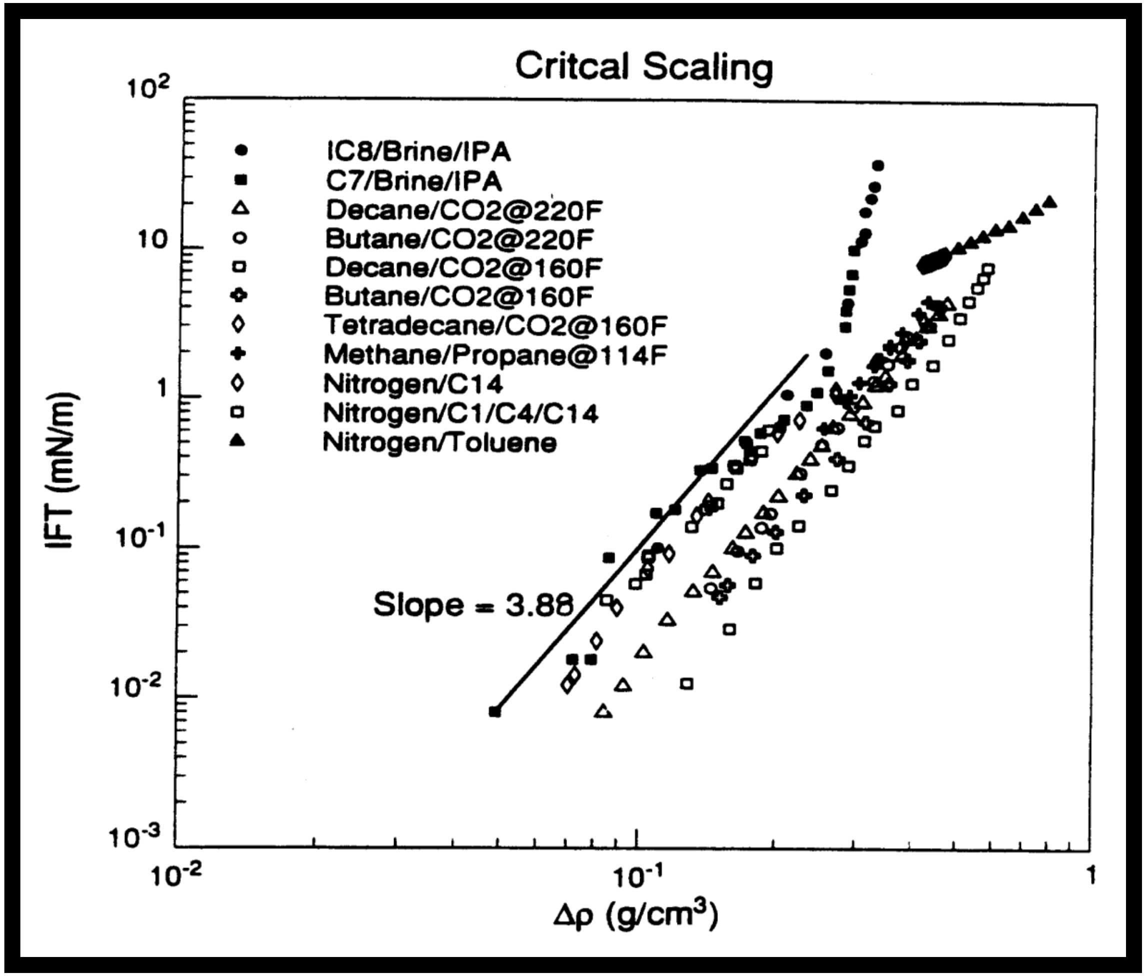
$$\Delta\rho = \Delta\rho^* \left[1 - \frac{T_r}{T_c}\right]^\beta \quad \text{where } \beta = 0.325$$

$$\sigma = \sigma^* \left[1 - \frac{T_r}{T_c}\right]^\gamma \quad \text{where } \gamma = 1.26$$

Test of Critical Scaling



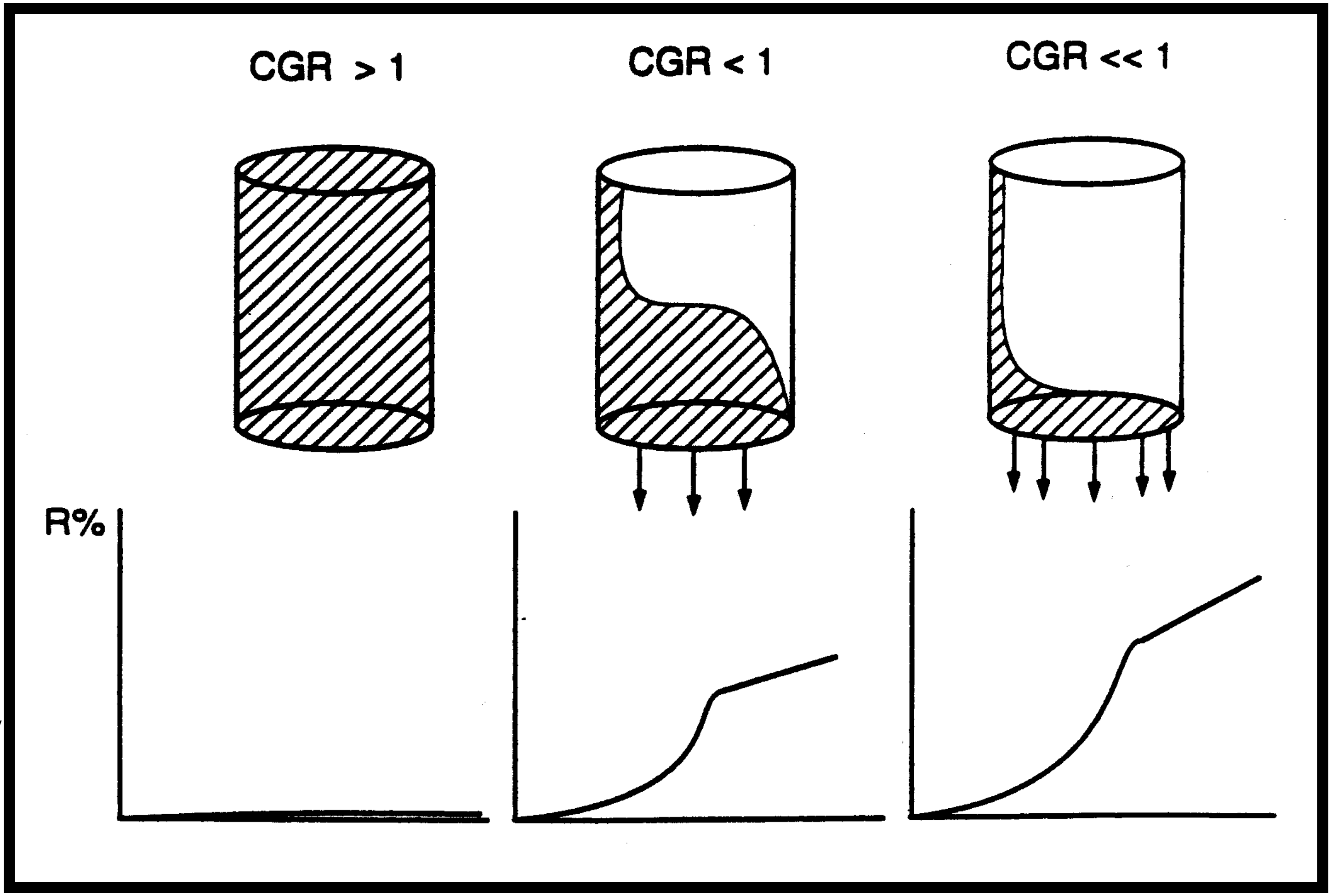
Critical Scaling



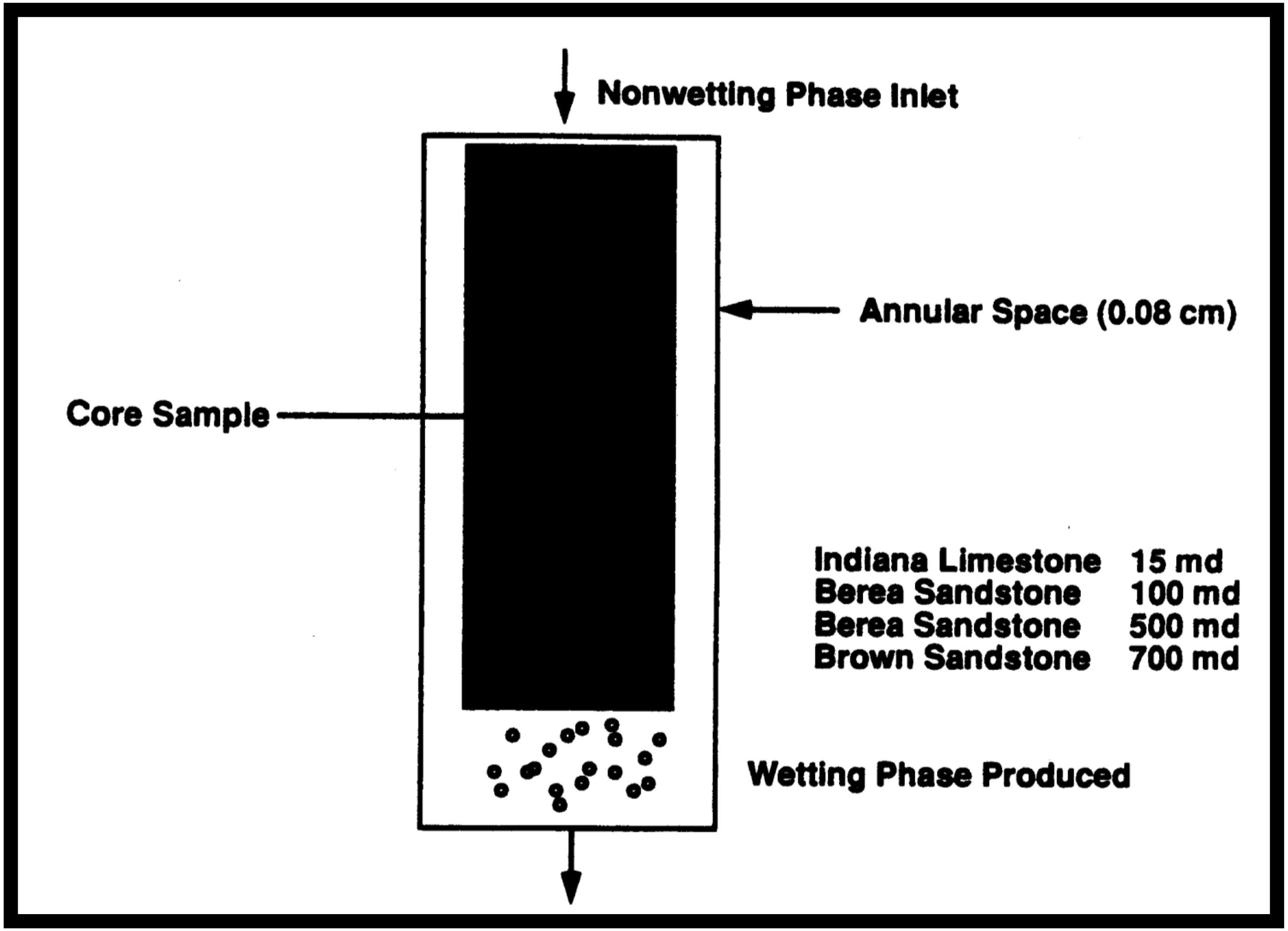
Drainage:
Mechanisms and Recovery

Drainage
Mechanisms

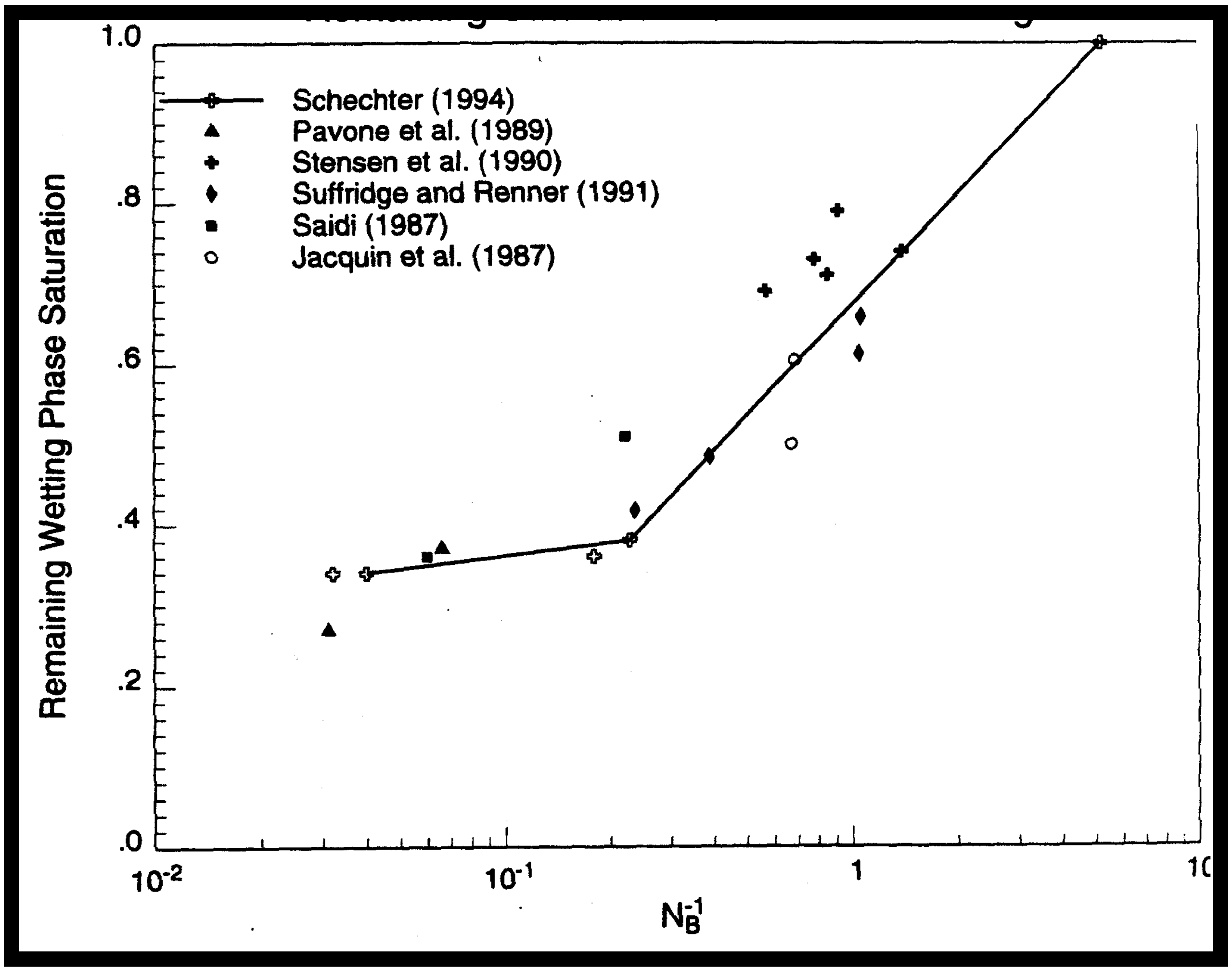
Drainage
Recovery



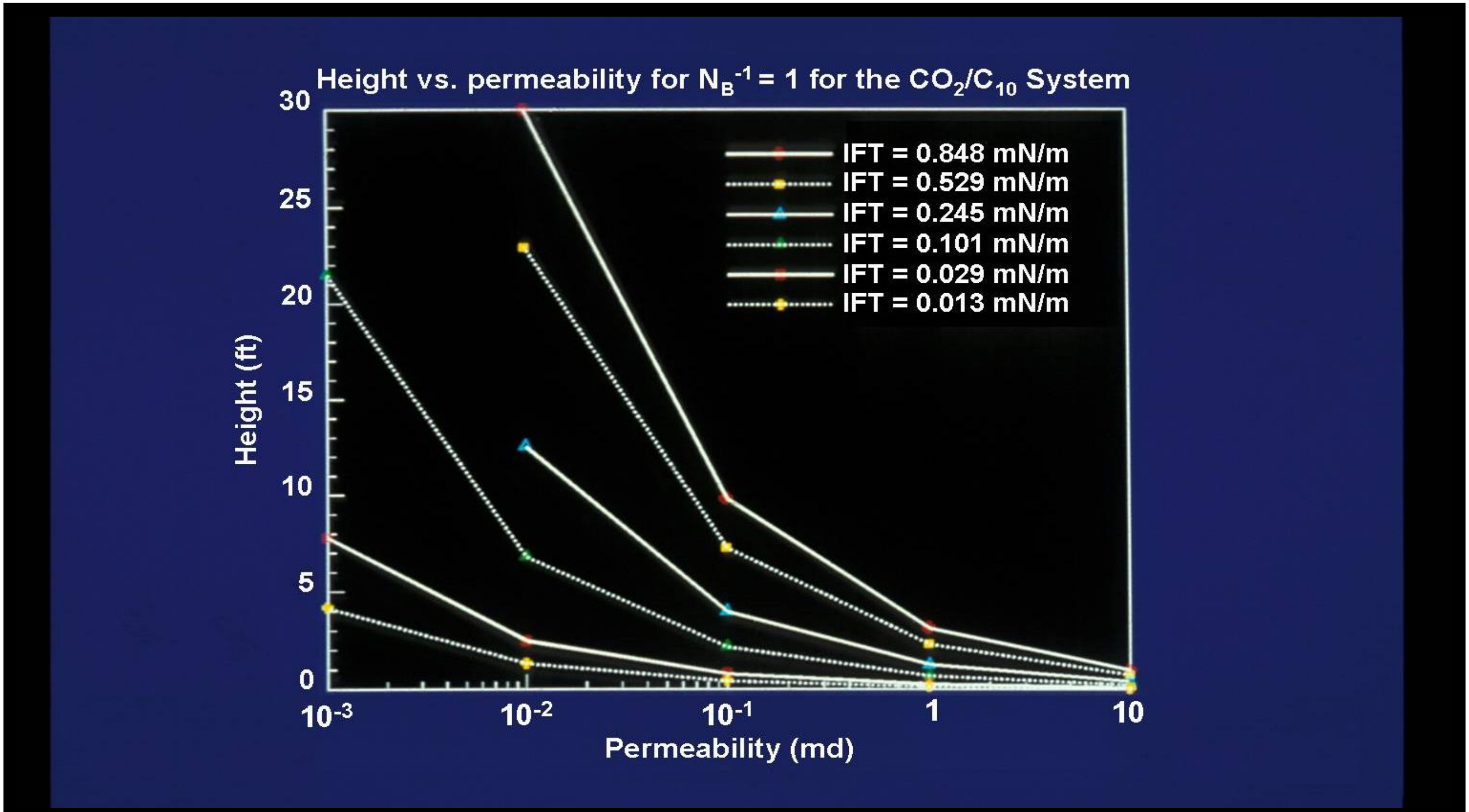
Gravity Drainage Cell



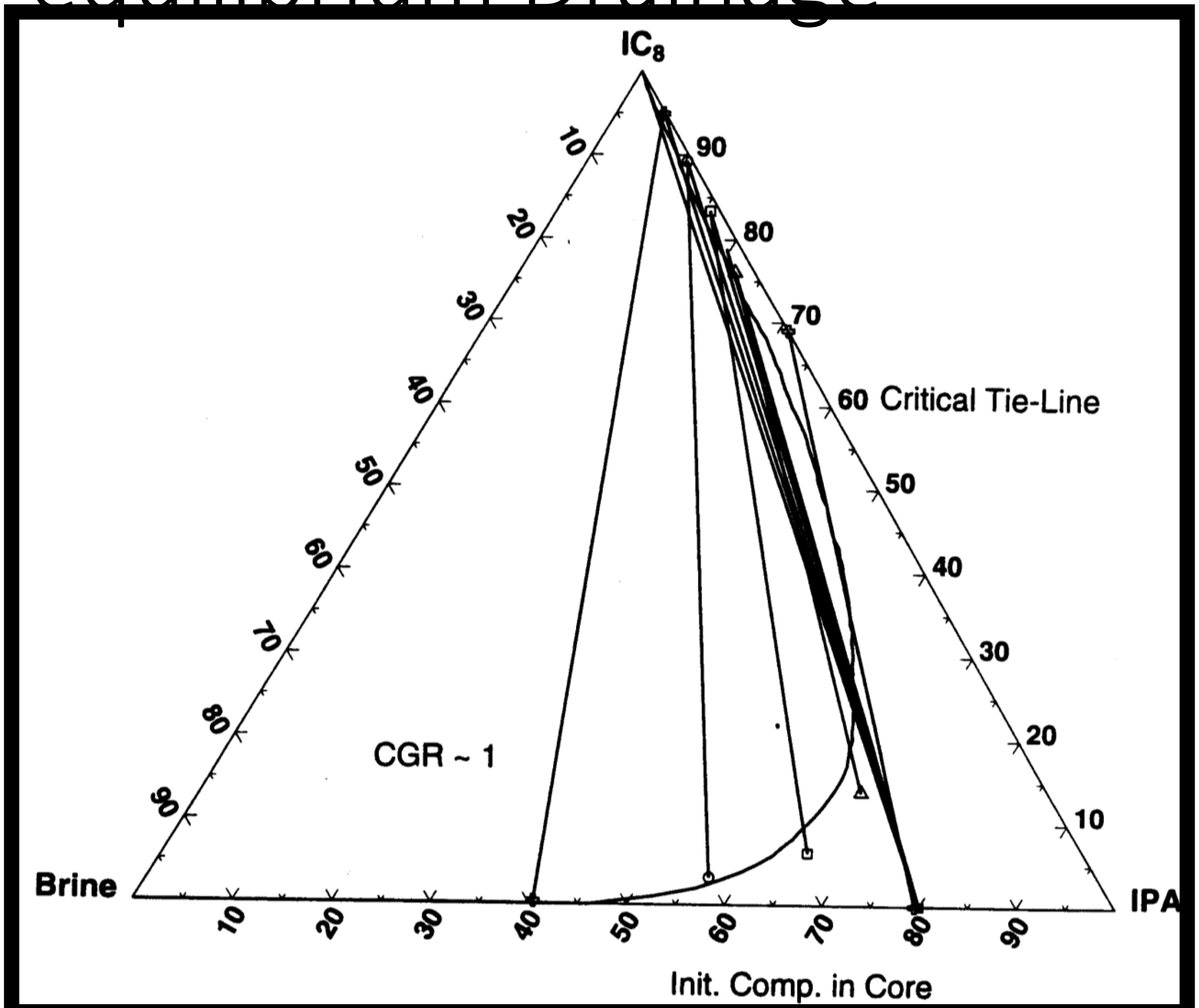
Remaining Saturation vs. CGR for Drainage



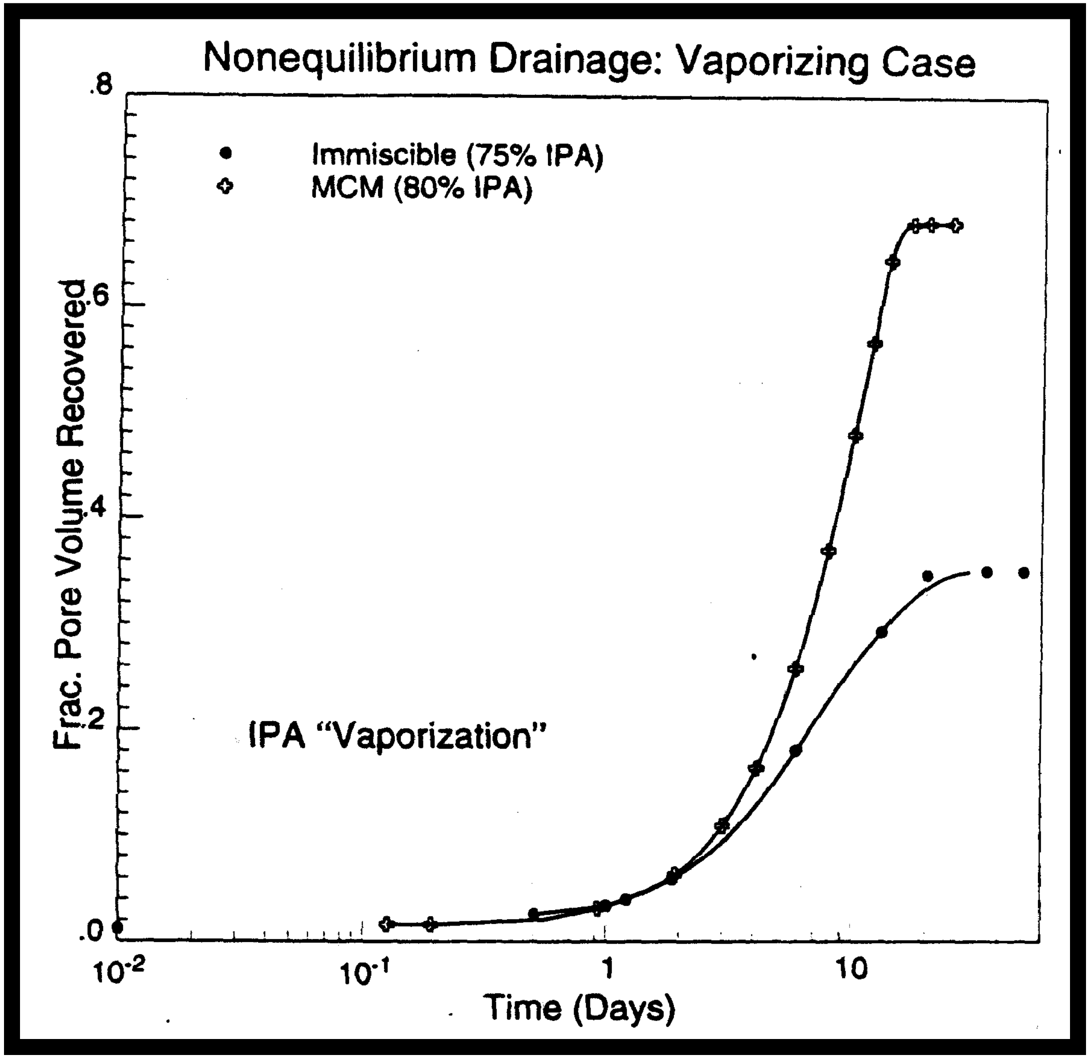
Height vs. Permeability

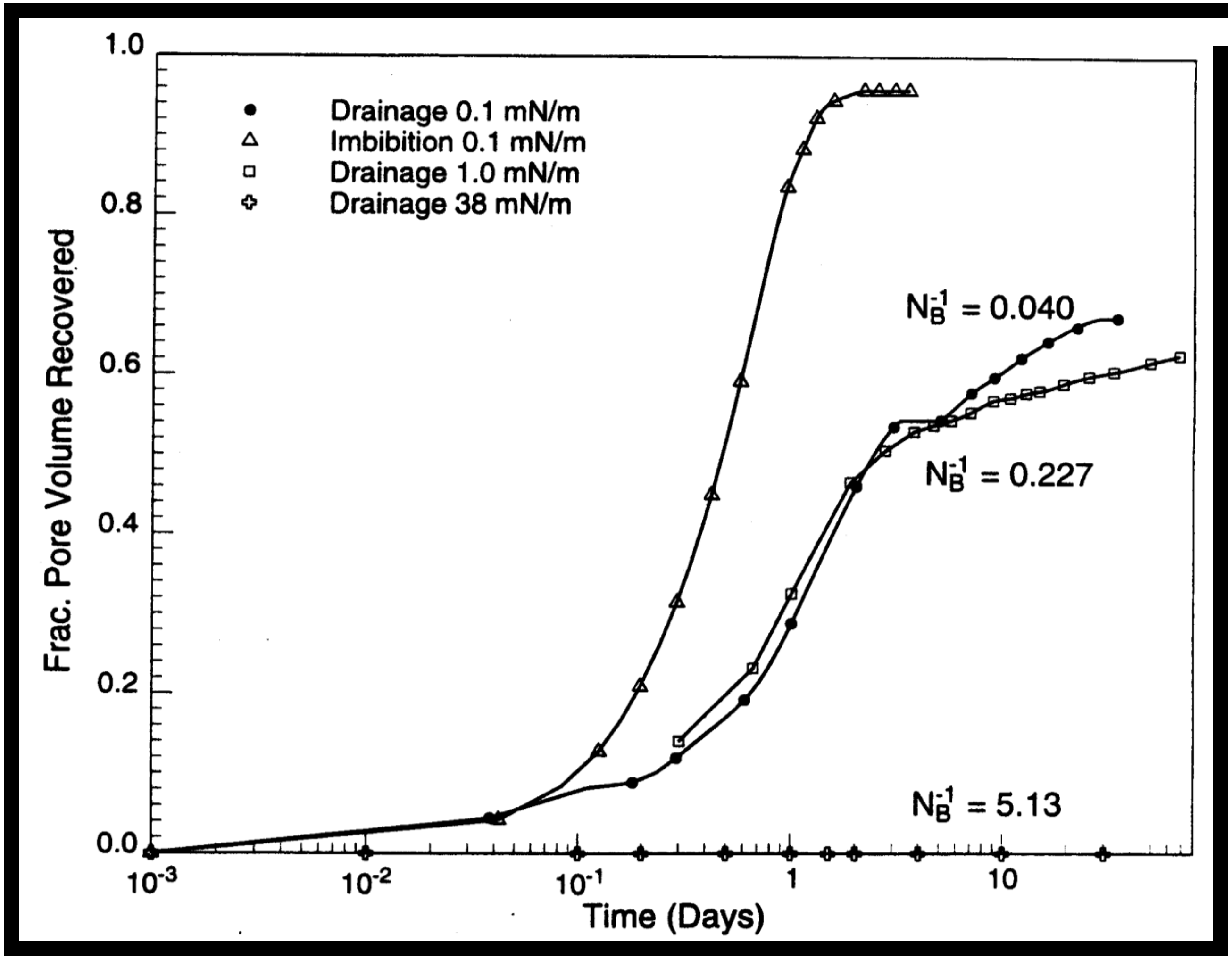


Non-equilibrium Drainage



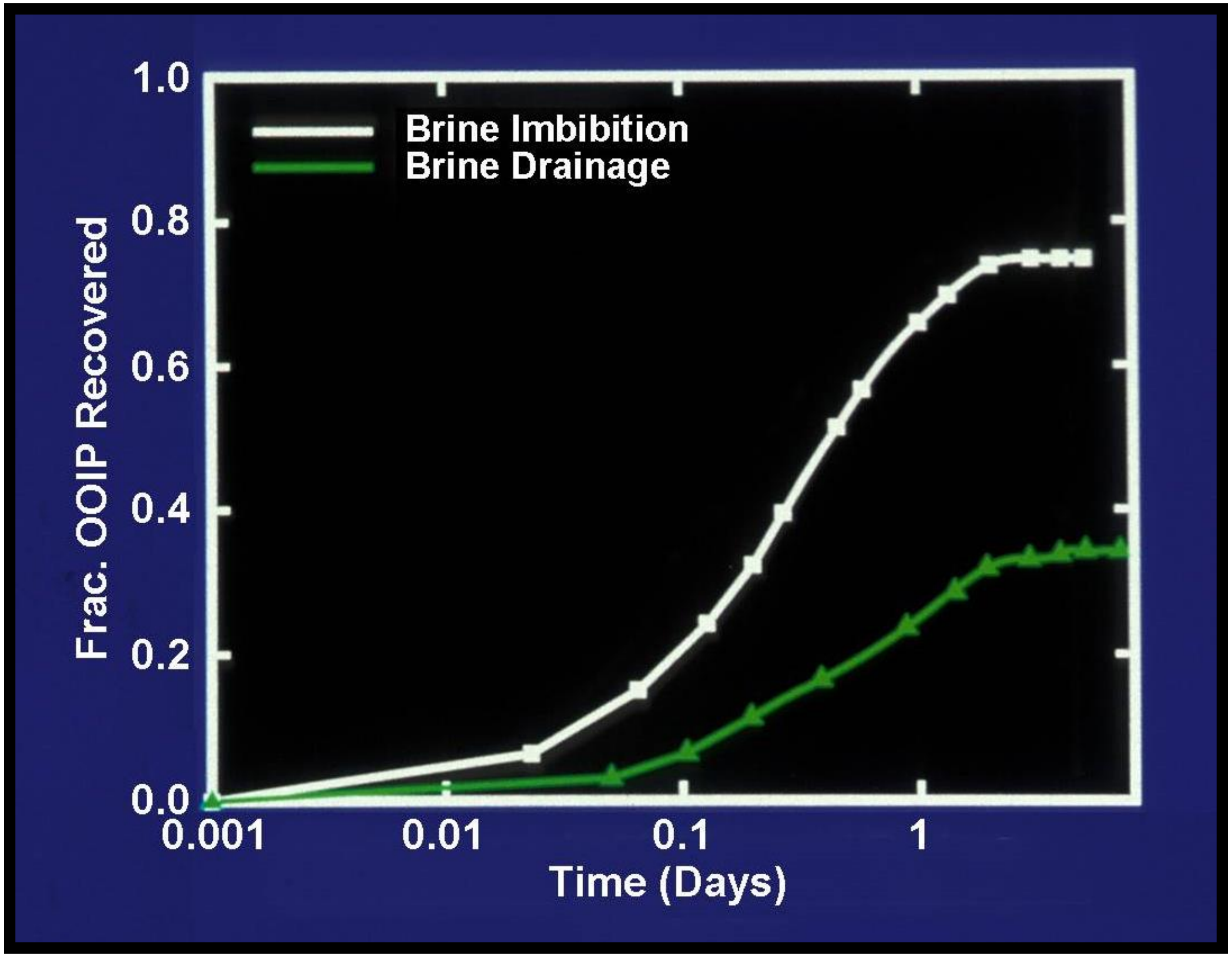
Non-equilibrium Drainage:





Drainage 0.1 mN/m
Imbibition 0.1 mN/m
Drainage 1.0 mN/m
Drainage 38 mN/m
$N_B^{-1} = 0.040$
$N_B^{-1} = 0.227$
$N_B^{-1} = 5.13$
Frac. Pore Volume Recovered
Time (Days)
1.0
0.8
0.6
0.4
0.2
0.0
10^{-3}
10^{-2}
10^{-1}
1
10

Spontaneous Imbibition and Drainage



Conclusions

- **Imbibition at high value of N_B^{-1} ($N_B^{-1} > 5$) is dominated by capillary forces, and the rate of imbibition is limited by the counter-current flow of the wetting and nonwetting phase.**

- **At low values of N_B^{-1} ($N_B^{-1} << 1$), imbibition is dominated by vertical flow driven by gravity forces.**

Conclusions

- For intermediate values of N_B^{-1}, the combined effects of gravity segregation and capillary-driver imbibition can lead to faster recovery of the nonwetting phase than is observed for either gravity-dominated of capillary-dominated flow.

- Gravity drainage of wetting phase from fully saturated vertical cores occurs for $N_B^{-1} < 1$.

Conclusions

- **Gas injection processes can be used to recover oil from fractured reservoirs by gravity drainage at low N_B^{-1}.**

N_2

Recovery factors under nitrogen injection

0%

Tidak ada
Rien
Niente
Nothing
هیچ چی
Hiçbir şey değil
Nada
niks
Niets
没有
لا شيئ
何もない
Nichts
कुछ भी तो नहीं
Ништа
Niets
Ingenting
아무것도
Τίποτα
ഒന്നുമില്ല
Ничего