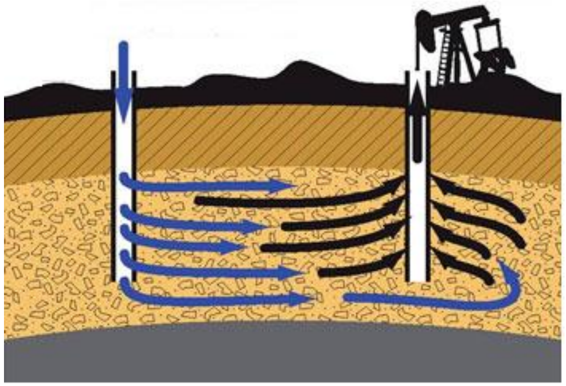
PNGE 443
Enhanced Oil Recovery

Chapter 1
Introduction to EOR



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Spring 2020-2021

Emre Özgür, Ph.D.

Academic Experience

2014 (PhD) , Middle East Technical University - Petroleum & Natural Gas Engineering Department, **(2009-2010 in Pennsylvania State University as an exchange student)**

2006 (MS), Middle East Technical University - Petroleum & Natural Gas Engineering Department

2004 (BS), Middle East Technical University - Petroleum & Natural Gas Engineering Department

Organizational Management Experience

Board Member of Society of Petroleum Engineers (SPE) Turkey Section **(2020-present)**

Member of Turkish Oil & Gas Committee in Global Methane Initiative (GMI) **(2017-present)**

Board Member of PMO, 'Chamber of Petroleum Engineers' in Turkey **(2012-2018)**

International Energy Agency (IEA) - Emergency Contact Member of Turkey **(2013 – 2014)**

Governmental Experience

2020 - present : Energy Expert, Presidency of Natural Resources Department - Turkish Ministry of Energy and Natural Resources

2019 - 2020 : Energy Expert, General Directorate of Energy Affairs - Turkish Ministry of Energy and Natural Resources

2018 - 2019 : Energy Expert, General Directorate of Mining & Petroleum Affairs - Turkish Ministry of Energy and Natural Resources

2013 - 2018 : Energy Expert, General Directorate of Petroleum Affairs - Turkish Ministry of Energy and Natural Resources

2004 - 2013 : Research and Teaching Assistant in METU Petroleum & Natural Gas Engineering Department **March, 2009 – March, 2010** : Research Scholar (Exchange Visitor) in Energy Institute - Pennsylvania State University, USA

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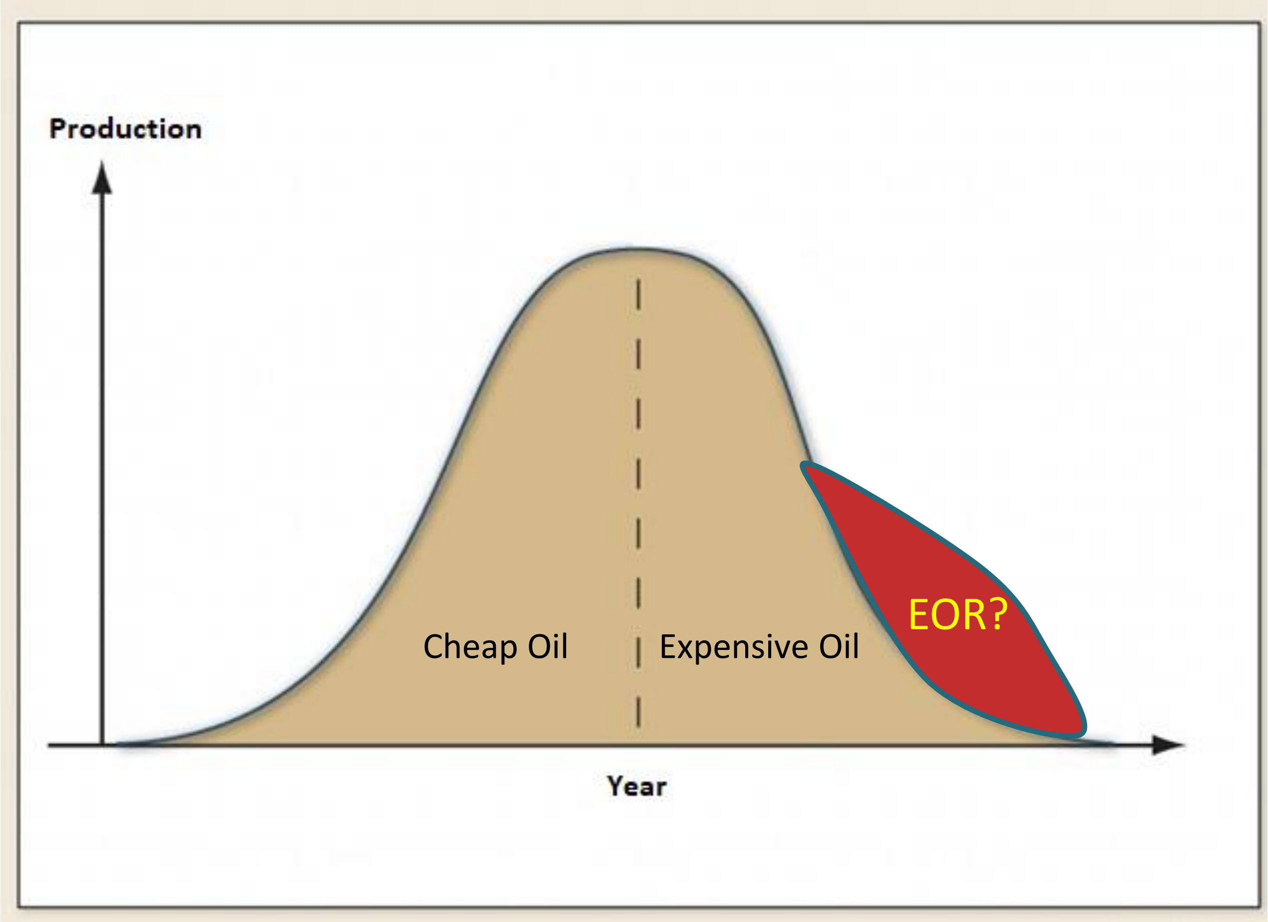
Syllabus

- 1 Introduction to EOR, World EOR Activities, EOR History, Classification of EOR methods
- 2 Screening criteria for appropriate EOR method
- 3 Review of rock and fluid properties; microscopic and macroscopic properties
- 4 Waterflooding
- 5 Thermal Methods
- 6 Gas Injection Methods
- 7 Chemical Injection Methods
- 8 Other EOR Methods
- 9 EOR History and Activities in Turkey, Evaluation of Oil Fields for EOR in Turkey

Enhanced Oil Recovery

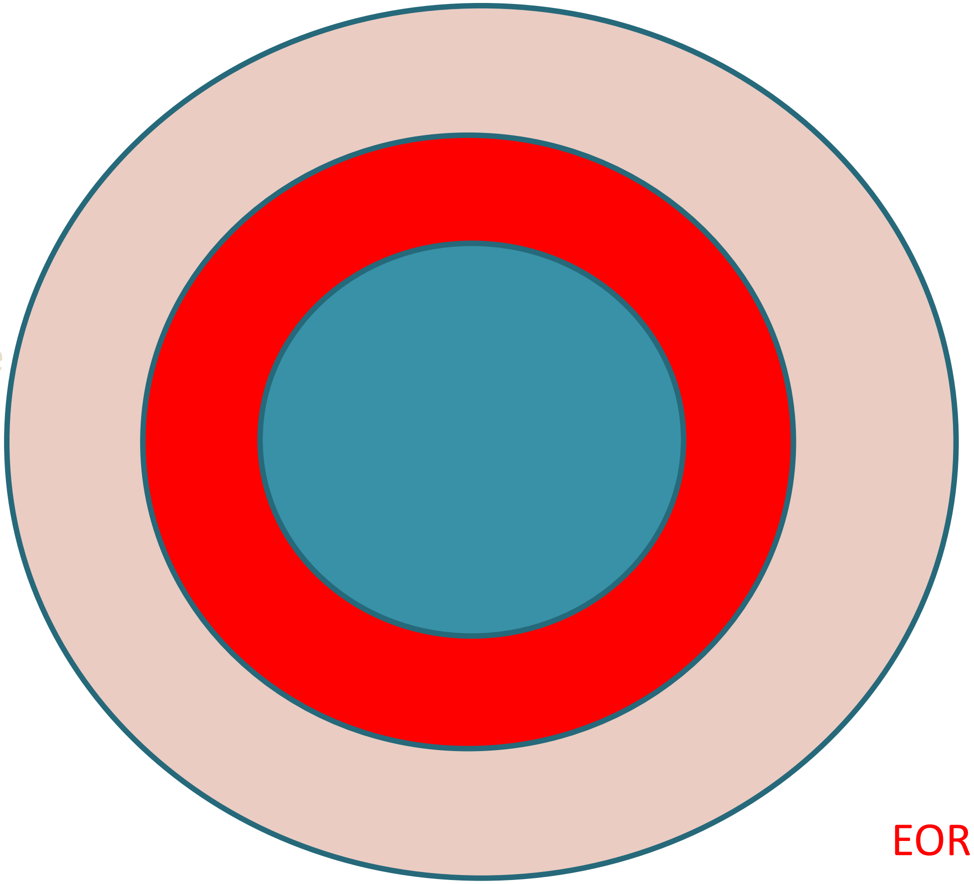
"The production of natural resources first increases rapidly, after seeing the peak, it decreases dramatically."



Hubbert Curve

Enhanced Oil Recovery

Technically Recoverable Oil by primary and secondary recovery

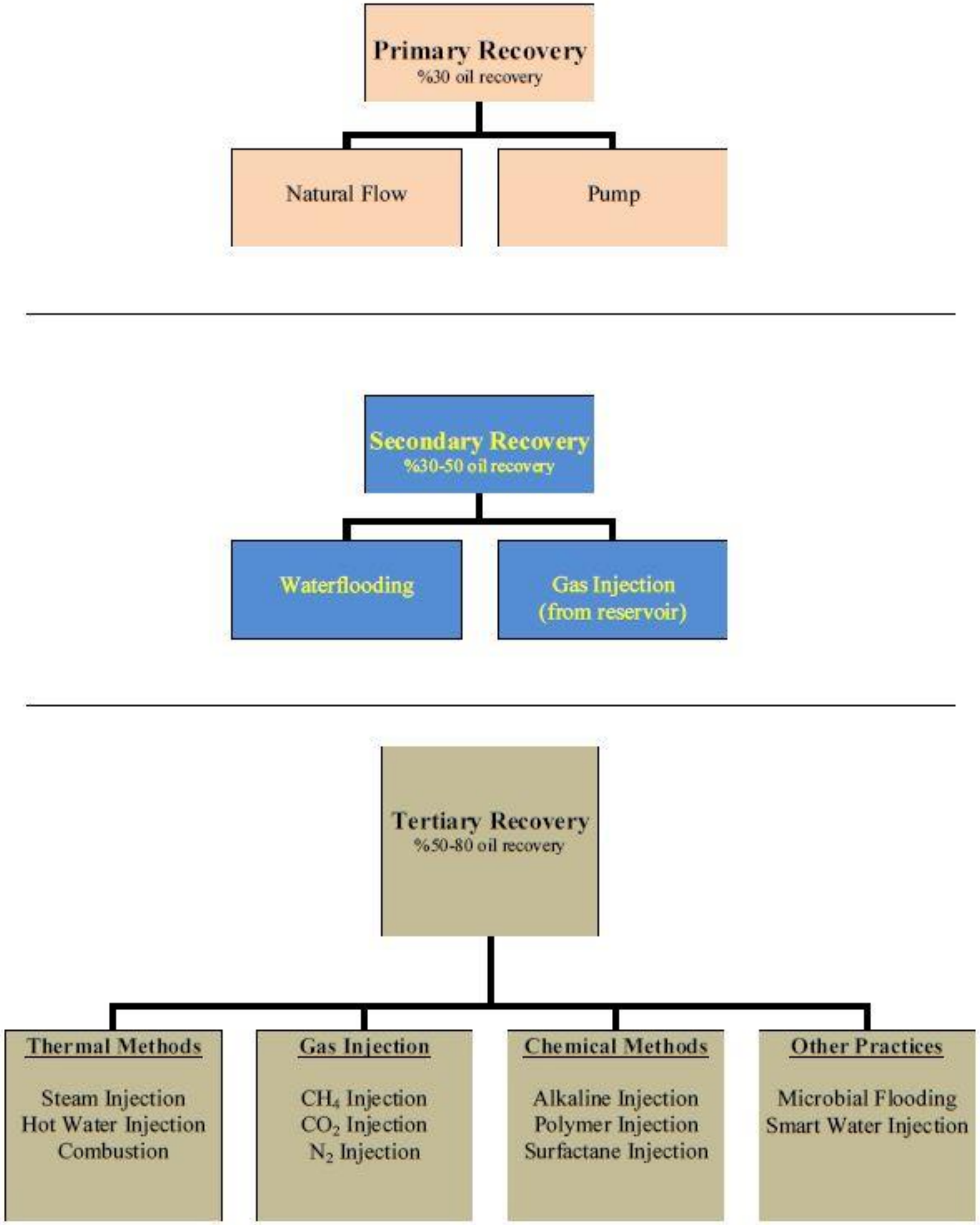


Original Oil In Place

EOR Increase

The ultimate objective of EOR is to produce additional amounts of oil left behind after primary and secondary production.

Enhanced Oil Recovery Methods



Primary Recovery
%30 oil recovery

- Natural Flow
- Pump

Secondary Recovery
%30-50 oil recovery

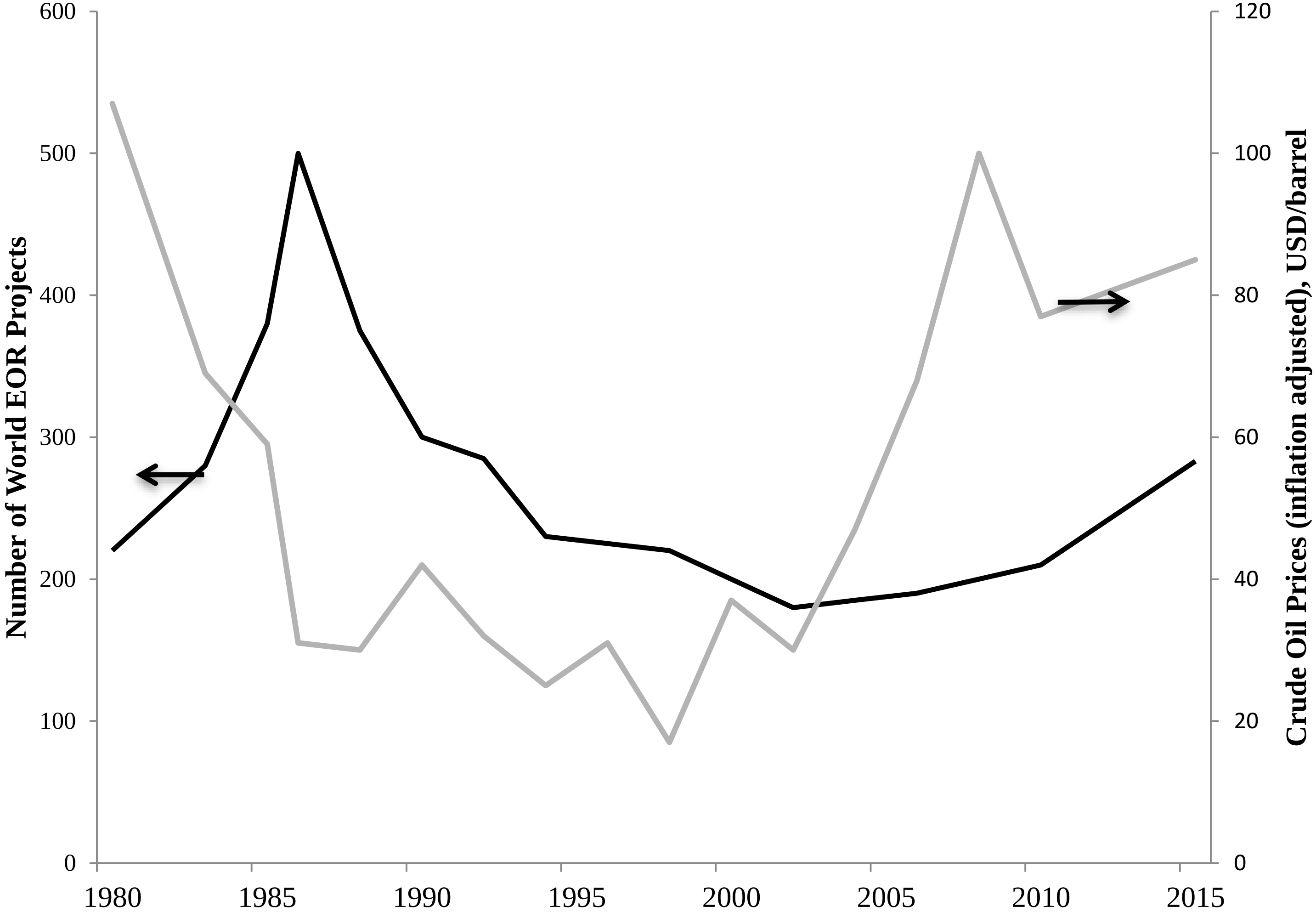
- Waterflooding
- Gas Injection (from reservoir)

Tertiary Recovery
%50-80 oil recovery

- Thermal Methods
  - Steam Injection
  - Hot Water Injection
  - Combustion
- Gas Injection
  - CH$_4$ Injection
  - CO$_2$ Injection
  - N$_2$ Injection
- Chemical Methods
  - Alkaline Injection
  - Polymer Injection
  - Surfactane Injection
- Other Practices
  - Microbial Flooding
  - Smart Water Injection

Enhanced Oil Recovery

Number of EOR Operations Worldwide by year vs Crude Oil Price



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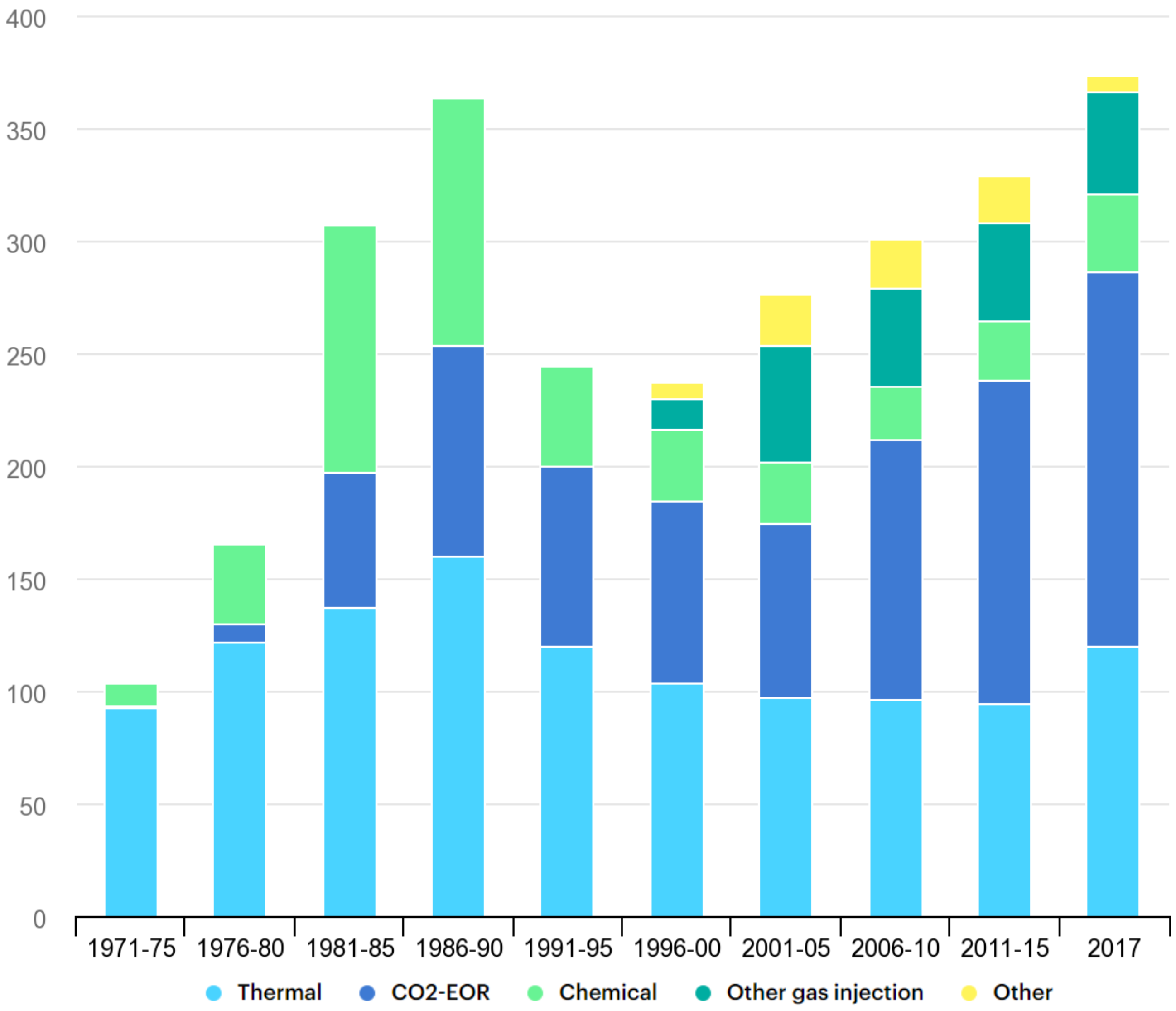
Enhanced Oil Recovery

Number of EOR Operations Globally , IEA



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Enhanced Oil Recovery

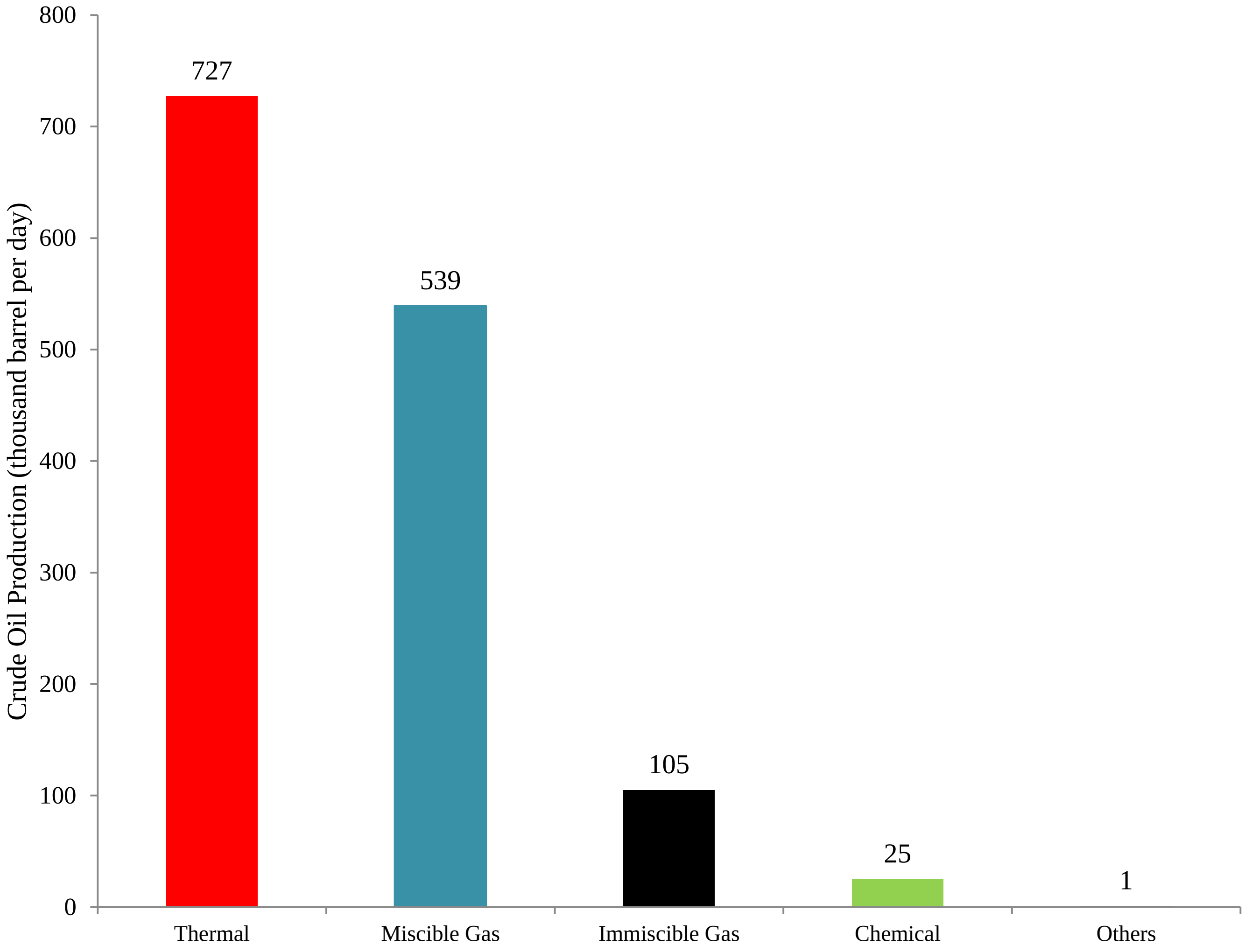
EOR Applications by country and method

Country	EOR Method	Number of Field
USA	Miscible CO_2 Injection	127
USA	Immiscible CO_2 Injection	9
USA	Miscible Hydrocarbon Gas Injection	12
USA	Immiscible Hydrocarbon Gas Injection	2
USA	Immiscible N_2 Injection	3
USA	Chemical Injection	3
Germany	Steam Injection	8
Brazil	Immiscible CO_2 Injection	1
Brazil	Miscible CO_2 Injection	2
Brazil	Microbial Injection	1
Brazil	Steam Injection	5
Indonesia	Steam Injection	2
Netherlands	Steam Injection	1
Canada	Miscible CO_2 Injection	7
Canada	Miscible Hydrocarbon Gas Injection	20
Canada	Steam Injection	10
Canada	Immiscible N_2 Injection	1
Canada	Polymer Injection	2
Egypt	Steam Injection	1
Trinidad	Steam Injection	9
Trinidad	Immiscible CO_2 Injection	5
Trinidad	Hot Water Injection	2
Turkey	Immiscible CO_2 Injection	1
Venezuela	Steam Injection	43
Venezuela	Combustion Flooding	1
Venezuela	Chemical Injection	1
Venezuela	Miscible Hydrocarbon Gas Injection	4

(Koottungal, 2014)

Enhanced Oil Recovery

World EOR Productions by Methods



Some EOR Statistics

Oil Production Rates in the World with EOR:

World Average: 2%

USA: 5%

Canada: 10%

Venezuela: 15%

Turkey: 10%

The Proportions of Formation Types with EOR in the World:

Carbonate: 20%

Sandstone: 80%

The Ratios of EOR Production Companies in the World by Types:

State Companies: 20%

Private Companies: 80%

Enhanced Oil Recovery

Primary Recovery

- Primary recovery (primary production) is the initial production stage.
- The recovery is as a result of the natural energy exists in the reservoir.
- The required energy is obtained from;
  - Gravity forces
  - Expanding rock and liquid
  - Releasing and expanding gas dissolved in oil while reducing reservoir pressure (depletion drive)
  - Expanding the gas cap
  - Expanding the active aquifer (natural water drive)
  - Combination of these factors

Enhanced Oil Recovery

Primary Recovery – Water Drive

- A water drive reservoir has a hydraulic connection between the reservoir and porous water saturated rock called an aquifer. The water in the aquifer is compressed. As reservoir pressure is reduced by oil production, the water expands, creating natural waterflood at the reservoir-aquifer boundary. When the aquifer is large and contains sufficient energy, the entire reservoir "waterflooded" by proper management of fluid withdrawal rates.

- Recovery efficiency of 35-75% of original oil in place (OOIP) are possible in water drive reservoirs.

Primary Recovery – Solution Gas Drive

- Crude oil under high pressure may contain large amounts of dissolved gas. When the reservoir pressure is reduced as fluids are withdrawn, gas comes out of solution and displaces oil from the reservoir to the producing wells. The efficiency of the solution gas drive depends on the amount of gas in solution, the rock and oil properties and the geological structure of the reservoir.
- Recoveries are low 10 to 15% of the OOIP.
- Recovery is low because the gas phase is more mobile than oil phase in the reservoir. As pressure declines, gas flows at a faster rate than oil, leading to rapid depletion of reservoir energy, which is noted by increasing gas-oil ratios in the field. Solution gas drive reservoirs are usually good candidates for waterflooding.

Primary Recovery – Gas Cap Drive

- When a reservoir has a large gas cap, there may be a large amount of energy stored in the form of compressed gas. The gas cap expands as fluids are withdrawn from the reservoir, displacing the oil by a gas drive assisted by gravity drainage. Expansion of the gas cap is limited by the desired pressure level in the reservoir after gas comes into production wells by gas production. Reservoirs with large gas caps generally are not considered to be good waterflood candidates. Pressure has been maintained in some of these reservoirs by injection of gas into the gas cap.

- Recovery efficiency is 20-40% of the OOIP.

Primary Recovery – Gravity Drainage

- Gravity drainage may be a primary producing mechanism in thick reservoirs that have good vertical communication or in steeply dipping reservoirs. Gravity drainage is a slow process because gas must migrate up structure or to the top of the formation to fill the space formerly occupied by oil. Gas migration is fast relative to oil drainage so that oil rates are controlled by the rate of oil drainage.

- Recovery efficiency is 5-15% of the OOIP.

Enhanced Oil Recovery

Secondary Recovery

- Secondary recovery is known as second stage of production.

- Secondary recovery process are;
  - Water injection
  - Gas injection
  - Water-gas mixture injection

- The main purpose in secondary recovery is to maintain reservoir pressure.

- As a rule, higher oil recovery coefficient is obtained with the introduction of secondary recovery even before the depletion of natural reservoir energy compared to the oil recovery coefficient during the primary oil recovery.

Enhanced Oil Recovery

- Crude oil production is separated into three phases: **primary** which is performed by natural flow or artificial lift (pump), **secondary** performed by either water or gas injection (by the gas produced from the reservoir) and tertiary which is also known as **Enhanced Oil Recovery (EOR)**.
- The terms EOR and Improved Oil Recovery (IOR) have been used loosely and interchangeably at times. IOR is a general term which implies improving oil recovery by any means. For example; acidizing, fracturing, horizontal wells, gel operation and etc.

EOR vs. Well Stimulation

Gas, Thermal, Chemical and etc.	Acidizing, hydraulic fracturing, gel operations
Field Scale	Well Scale
Late production increase	Quick production increase
High increase in cumulative production	Low increase in cumulative production
Expensive	Cheap
Only in crude oil fields	Both oil and gas fields

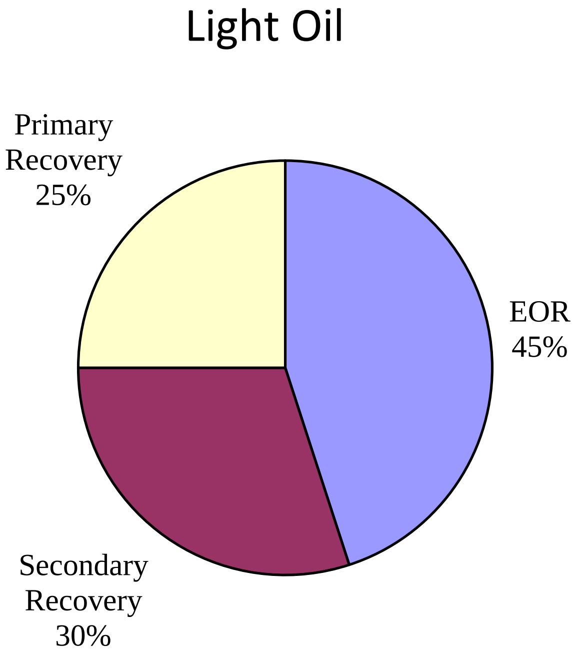
Enhanced Oil Recovery

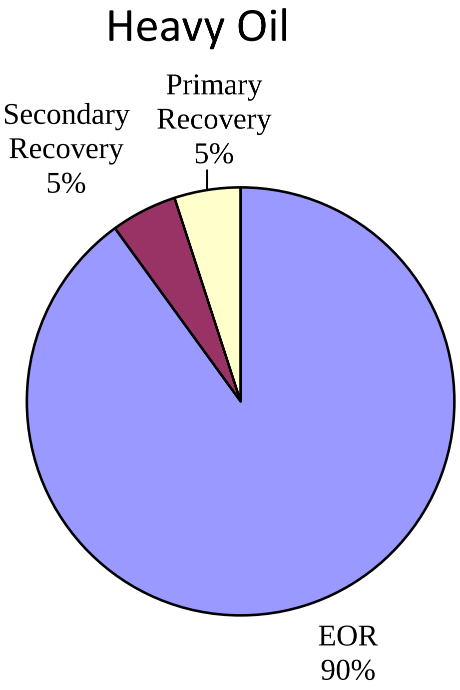
- The active usage of EOR projects worldwide started after first oil crisis in 1973 and then showed wavy behavior due to instable crude oil prices. The number of EOR projects increase with increasing price of crude oil.

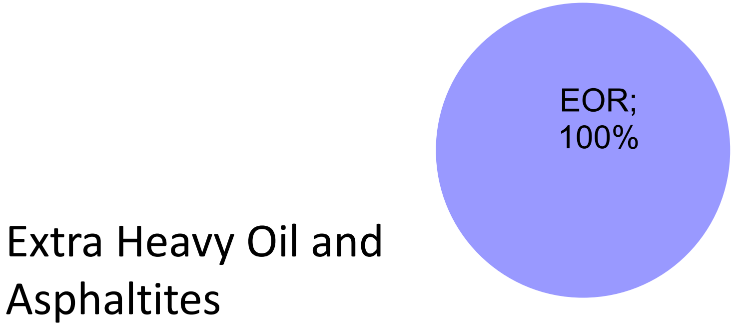
- The importance of EOR increases with the decrease of API gravity of oil since the share of crude oil that can be produced by EOR increases as the API gravity of crude oil decreases. In case of heavy crude oil reservoir conditions the EOR ratio can even become some 90%.

Enhanced Oil Recovery

Potentials of primary, secondary and tertiary production methods by petroleum type







Enhanced Oil Recovery

- Although EOR projects are expensive operations and require skilled staff, the existing infrastructure and pipelines in the fields provide advantage and easy access of produced oil to markets with no additional exploration costs.
- 20% of the EOR based crude oil production worldwide is performed by national oil companies. The rest is produced by private oil companies showing the positive feasibility of the EOR projects worldwide.

Enhanced Oil Recovery

- The current ratio of crude oil production by EOR methods is about 2% (2 million barrel per day) of global production; however according to the International Energy Agency report, this ratio will increase to 4.25% (4.3 million barrel per day) by 2040.
- The systemic application of all available EOR technologies across the global conventional crude oil resource base could in theory unlock up to 300 billion barrels of oil.

Enhanced Oil Recovery

- The average recovery factor from mature oilfields around the world is somewhere between 20% and 40%. This contrasts with a typical recovery factor from gas fields of between 80% and 90%. At current production rates existing proven oil reserves will last 50 years.

- The majority of oil companies today are focusing on maximizing the recovery factor from their oilfields as well as maintaining an economic oil rate. This is because it is becoming increasingly difficult to discover new oilfields.

Enhanced Oil Recovery

- The average recovery rate for the crude oil fields is 1/3 of the reservoir volume worldwide presently. The carbonate reservoirs have lower recovery rates compared to sandstone reservoirs due to their fractured structure, heterogeneity, oil-wet tendency, lower permeability and porosity.
- 80% of the EOR crude oil production comes from sandstone reservoirs worldwide, other 20% from carbonate reservoirs.

Enhanced Oil Recovery

- Apart from the known enhanced oil recovery methods, alternative production methods have also been applied in the petroleum industry to date. Applications include dynamite explosion, nuclear bomb explosion, electromagnetic heating, hydraulic fracturing, acid injection, gel injection and similar applications. Since the methods mentioned are well scaled in terms of application, they are included in the classification of well completion methods.

Enhanced Oil Recovery History

Gas Injection Projects

- Historically, immiscible gas injection was first used for reservoir pressure maintenance. The first such projects were initiated in the 1930s and used hydrocarbon gas (e.g., Oklahoma City field and Cunningham pool in the US and Bahrain field in Bahrain).
- CO_2 injection was first employed in the US in the early 1970s in Texas, was successfully used in Texas and New Mexico States.

Enhanced Oil Recovery History

Thermal Recovery Projects

- The idea of in-situ combustion was patented in 1923 in the United States. The first field test attempts to ignite oil in a very shallow reservoir were conducted in 1930s in Soviet Union, but there was no continuation with a more extended field pilot or semicommercial operations. The field tests were started again in the US during 1952 and extended after the first favorable laboratory results were published.

- Thermal recovery was first applied in USA and Venezuela in the 1960s.

Enhanced Oil Recovery History

In-situ Combustion Projects

- West Newport, CA, USA – 1958
  Midway-Sunset, CA, USA – 1960
  Miga, Venezuela – 1964
  Suplaco, Romania – 1967
  Bellevue, LA, USA – 1967
  Trix-Liz, TX, USA – 1968
  Brea Olinda, CA - 1972

Enhanced Oil Recovery

Thermal Methods

- Hot Water Injection

  \- It is an inefficient operation with high heat losses. It is applied in areas close to the surface.

- Fire Flooding (In-situ Combustion)

  \- It is a complex, expensive operation that is difficult to control.

- Steam Injection

  \- It is the most suitable method among thermal methods.

Enhanced Oil Recovery

Gas Injection

- CH4 Injection

  - It is a method used in adjacent areas where gas contains.

- N2 Injection

  - It is a method used in fields containing light oil found in very deep formations. It is rarely used.

- CO2 Injection

  - It is a widely used method. It is preferred because it increases the mobility of oil more easily and it has environmental advantages.

Chemical Methods

- Alkali Injection

  - It is the cheapest method among chemical operations, but it has very little application since it has very limited working criteria (acidic oil, sandstone formation, etc.).

- Polymer Injection

  - In the fields where water injection is applied, it is aimed to reduce the viscosity difference between oil and water and to realize an efficient injection operation. By adding the polymer to the water, the viscosity of the water is increased and it is brought closer to that of the crude oil.

- Surfactant Injection

  - It is the most expensive method among chemical operations. It aims for the oil to flow easily by weakening the bonds between oil and water / rock and reducing the interface tension.

Other EOR Methods

- Microbial Injection

  - Injected microorganisms break the strong bonds in crude oil over time, reducing the viscosity of crude oil, thus enabling it to be produced easily. At the same time, the production of some chemicals as by-products weakens the bonds between oil and rock. The method is not yet a proven and well-established method in all aspects.

- Smart Water Injection

  - In this method, the water injected with low salinity replaces the oil attached to the rock and allows the oil to flow. Most of the studies on the method are laboratory-based, and there is not enough study and information in the literature.

Enhanced Oil Recovery

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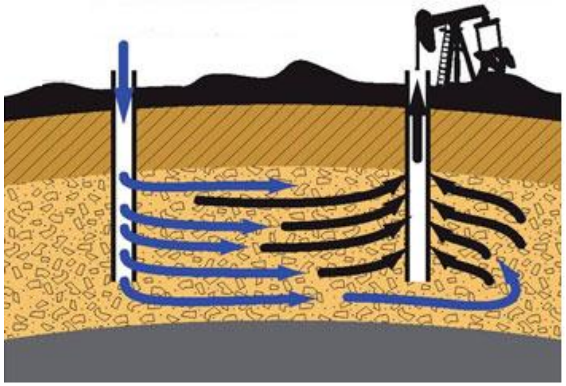
- Dr. K. Gizem Gül Ertunç, PETE 443 Lecture Notes
- Dr. Doruk Alp, PETE 443 Lecture Notes
- Dr. Ender Okandan, PETE 443 Lecture Notes

PNGE 443
Enhanced Oil Recovery

Chapter 2
Screening Criteria for Appropriate EOR Method



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Function of EOR:

- Boost the natural energy in the reservoir
- Interact with the reservoir rock/oil system to create conditions favorable for residual oil recovery that include among others:

  - Reduction of the interfacial tension between the displacing fluid and oil

  - Increase the capillary number

  - Reduce capillary forces

  - Increase the drive water viscosity

  - Provide mobility-control

  - Oil swelling

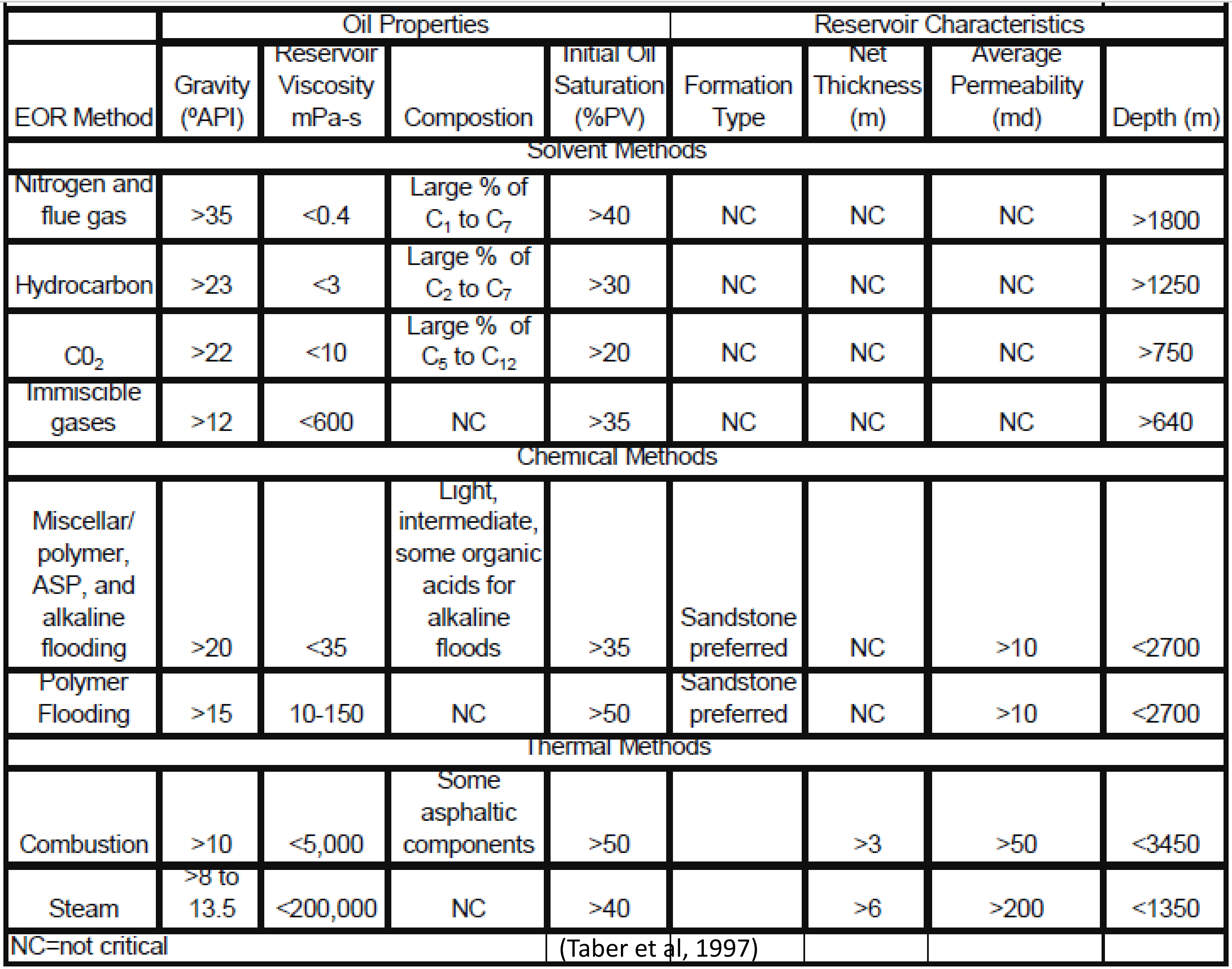
  - Oil viscosity reduction

  - Alteration of the reservoir rock wettability

EOR Screening Guidelines:

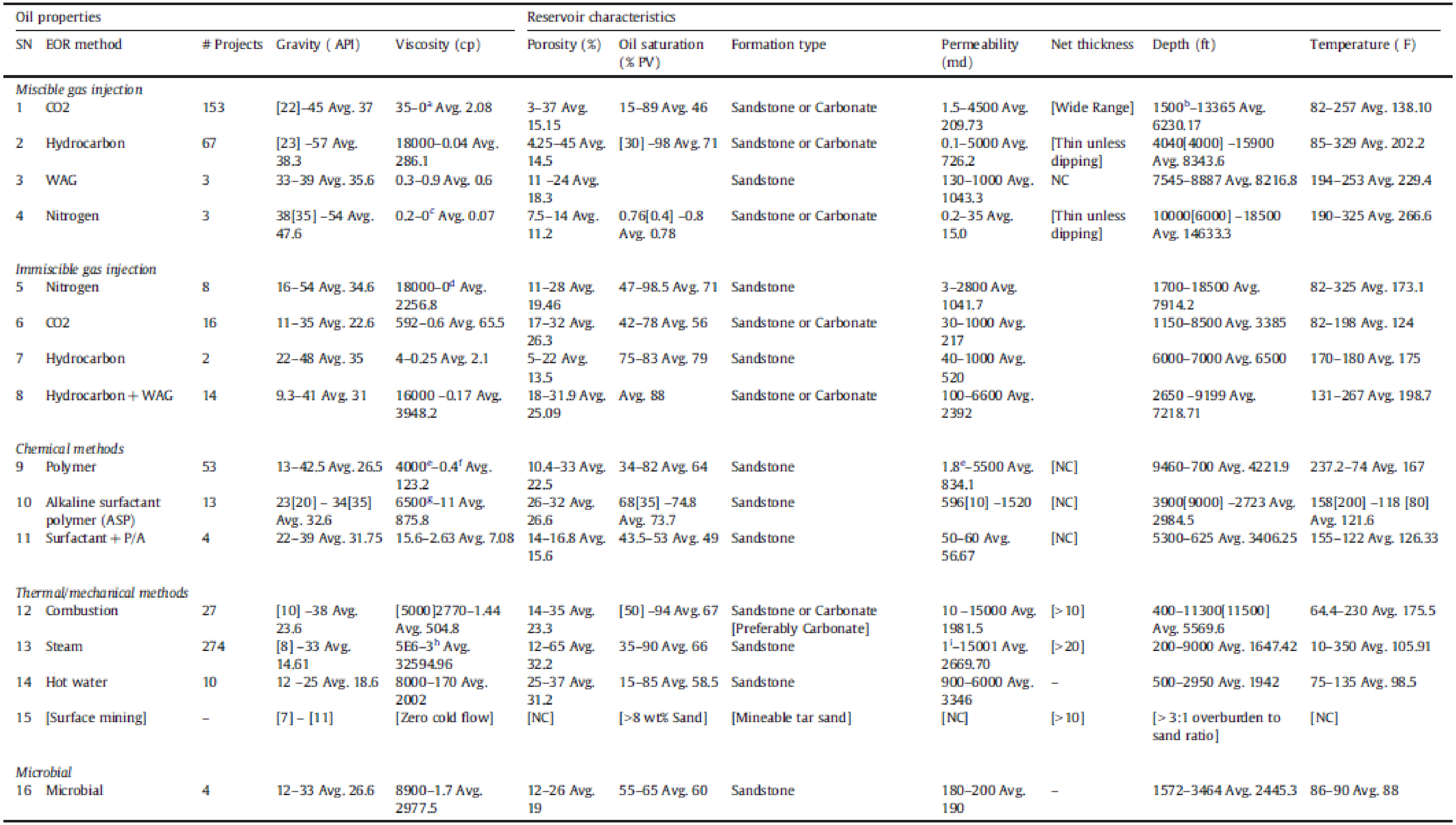
- Reservoir Conditions: temperature and pressure
- Reservoir Fluid Properties: oil viscosity, oil density and formation water salinity
- Reservoir Geology: rock type, formation depth, permeability and porosity

Summary of Screening Criteria for EOR Methods



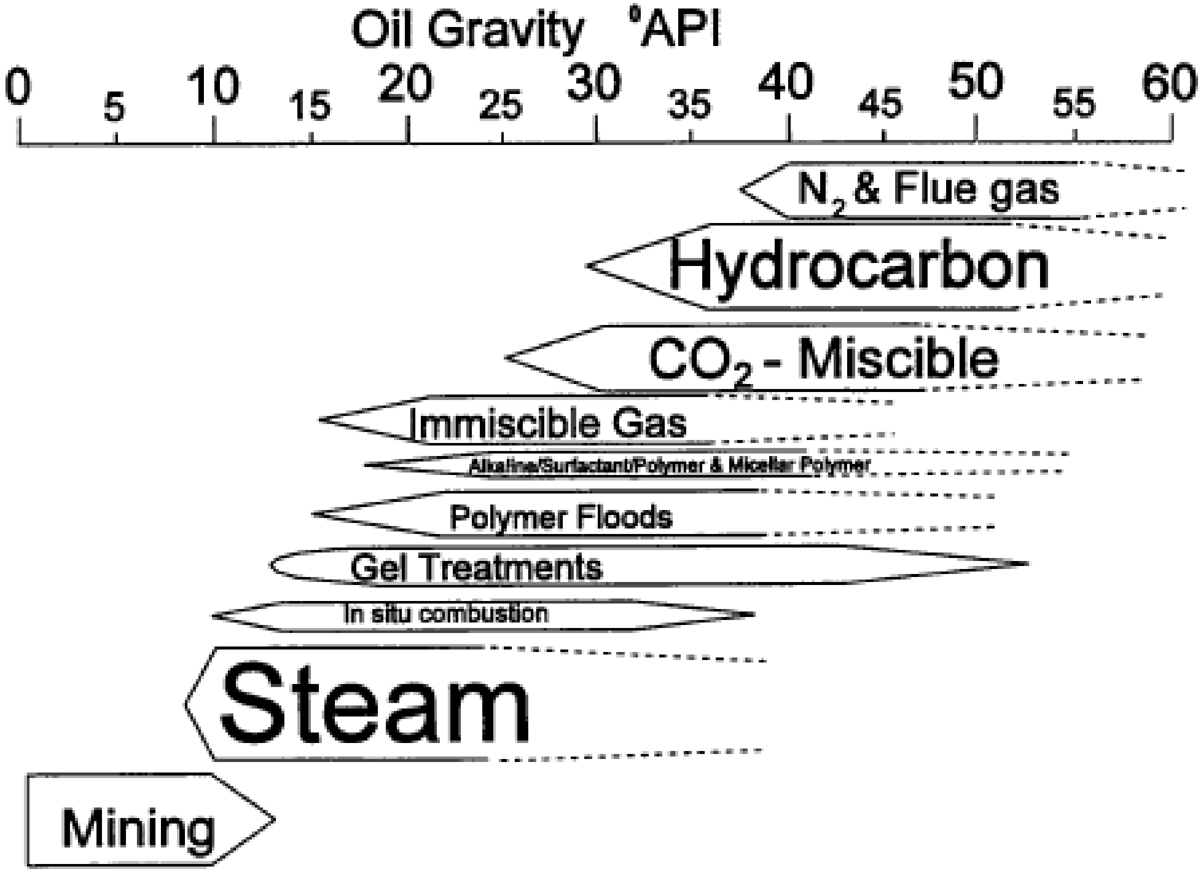
	Oil Properties				Reservoir Characteristics			
EOR Method	Gravity (ºAPI)	Reservoir Viscosity mPa-s	Compostion	Initial Oil Saturation (%PV)	Formation Type	Net Thickness (m)	Average Permeability (md)	Depth (m)
				Solvent Methods				
Nitrogen and flue gas	>35	<0.4	Large % of C_1 to C_7	>40	NC	NC	NC	>1800
Hydrocarbon	>23	<3	Large % of C_2 to C_7	>30	NC	NC	NC	>1250
C0$_2$	>22	<10	Large % of C_5 to C_{12}	>20	NC	NC	NC	>750
Immiscible gases	>12	<600	NC	>35	NC	NC	NC	>640
				Chemical Methods				
Miscellar/ polymer, ASP, and alkaline flooding	>20	<35	Light, intermediate, some organic acids for alkaline floods	>35	Sandstone preferred	NC	>10	<2700
Polymer Flooding	>15	10-150	NC	>50	Sandstone preferred	NC	>10	<2700
				Thermal Methods				
Combustion	>10	<5,000	Some asphaltic components	>50		>3	>50	<3450
Steam	>8 to 13.5	<200,000	NC	>40		>6	>200	<1350
NC=not critical				(Taber et al, 1997)				

Summary of Screening Criteria for EOR Methods



Oil properties					Reservoir characteristics						
SN	EOR method	# Projects	Gravity (API)	Viscosity (cp)	Porosity (%)	Oil saturation (% PV)	Formation type	Permeability (md)	Net thickness	Depth (ft)	Temperature (F)
Miscible gas injection											
1	CO2	153	[22]–45 Avg. 37	35–0^{a} Avg. 2.08	3–37 Avg. 15.15	15–89 Avg. 46	Sandstone or Carbonate	1.5–4500 Avg. 209.73	[Wide Range]	1500^{b}–13365 Avg. 6230.17	82–257 Avg. 138.10
2	Hydrocarbon	67	[23] –57 Avg. 38.3	18000–0.04 Avg. 286.1	4.25–45 Avg. 14.5	[30] –98 Avg. 71	Sandstone or Carbonate	0.1–5000 Avg. 726.2	[Thin unless dipping]	4040[4000] –15900 Avg. 8343.6	85–329 Avg. 202.2
3	WAG	3	33–39 Avg. 35.6	0.3–0.9 Avg. 0.6	11 –24 Avg. 18.3		Sandstone	130–1000 Avg. 1043.3	NC	7545–8887 Avg. 8216.8	194–253 Avg. 229.4
4	Nitrogen	3	38[35] –54 Avg. 47.6	0.2–0^{c} Avg. 0.07	7.5–14 Avg. 11.2	0.76[0.4] –0.8 Avg. 0.78	Sandstone or Carbonate	0.2–35 Avg. 15.0	[Thin unless dipping]	10000[6000] –18500 Avg. 14633.3	190–325 Avg. 266.6
Immiscible gas injection											
5	Nitrogen	8	16–54 Avg. 34.6	18000–0^{d} Avg. 2256.8	11–28 Avg. 19.46	47–98.5 Avg. 71	Sandstone	3–2800 Avg. 1041.7		1700–18500 Avg. 7914.2	82–325 Avg. 173.1
6	CO2	16	11–35 Avg. 22.6	592–0.6 Avg. 65.5	17–32 Avg. 26.3	42–78 Avg. 56	Sandstone or Carbonate	30–1000 Avg. 217		1150–8500 Avg. 3385	82–198 Avg. 124
7	Hydrocarbon	2	22–48 Avg. 35	4–0.25 Avg. 2.1	5–22 Avg. 13.5	75–83 Avg. 79	Sandstone	40–1000 Avg. 520		6000–7000 Avg. 6500	170–180 Avg. 175
8	Hydrocarbon + WAG	14	9.3–41 Avg. 31	16000 –0.17 Avg. 3948.2	18–31.9 Avg. 25.09	Avg. 88	Sandstone or Carbonate	100–6600 Avg. 2392		2650 –9199 Avg. 7218.71	131–267 Avg. 198.7
Chemical methods											
9	Polymer	53	13–42.5 Avg. 26.5	4000^{e}–0.4^{f} Avg. 123.2	10.4–33 Avg. 22.5	34–82 Avg. 64	Sandstone	1.8^{e}–5500 Avg. 834.1	[NC]	9460–700 Avg. 4221.9	237.2–74 Avg. 167
10	Alkaline surfactant polymer (ASP)	13	23[20] – 34[35] Avg. 32.6	6500^{g}–11 Avg. 875.8	26–32 Avg. 26.6	68[35] –74.8 Avg. 73.7	Sandstone	596[10] –1520	[NC]	3900[9000] –2723 Avg. 2984.5	158[200] –118 [80] Avg. 121.6
11	Surfactant + P/A	4	22–39 Avg. 31.75	15.6–2.63 Avg. 7.08	14–16.8 Avg. 15.6	43.5–53 Avg. 49	Sandstone	50–60 Avg. 56.67	[NC]	5300–625 Avg. 3406.25	155–122 Avg. 126.33
Thermal/mechanical methods											
12	Combustion	27	[10] –38 Avg. 23.6	[5000]2770–1.44 Avg. 504.8	14–35 Avg. 23.3	[50] –94 Avg. 67	Sandstone or Carbonate [Preferably Carbonate]	10 –15000 Avg. 1981.5	[> 10]	400–11300[11500] Avg. 5569.6	64.4–230 Avg. 175.5
13	Steam	274	[8] –33 Avg. 14.61	5E6–3^{h} Avg. 32594.96	12–65 Avg. 32.2	35–90 Avg. 66	Sandstone	1^{i}–15001 Avg. 2669.70	[> 20]	200–9000 Avg. 1647.42	10–350 Avg. 105.91
14	Hot water	10	12 –25 Avg. 18.6	8000–170 Avg. 2002	25–37 Avg. 31.2	15–85 Avg. 58.5	Sandstone	900–6000 Avg. 3346	–	500–2950 Avg. 1942	75–135 Avg. 98.5
15	[Surface mining]	–	[7] – [11]	[Zero cold flow]	[NC]	[>8 wt% Sand]	[Mineable tar sand]	[NC]	[> 10]	[> 3:1 overburden to sand ratio]	[NC]
Microbial											
16	Microbial	4	12–33 Avg. 26.6	8900–1.7 Avg. 2977.5	12–26 Avg. 19	55–65 Avg. 60	Sandstone	180–200 Avg. 190	–	1572–3464 Avg. 2445.3	86–90 Avg. 88

Summary of Screening Criteria for EOR Methods



API gravity range of oil that is most effective for EOR methods. Relative production is shown by size of type.

Nitrogen and Flue Gas Flooding

Description

- Nitrogen and flue gas are oil recovery methods that use these inexpensive nonhydrocarbon gases to displace oil in systems that may be either miscible or immiscible depending on the pressure and oil composition. Because of their low cost, large volumes of these gases may be injected. Nitrogen and flue gas are also considered for use as chase gases in hydrocarbon-miscible and CO_2 floods.

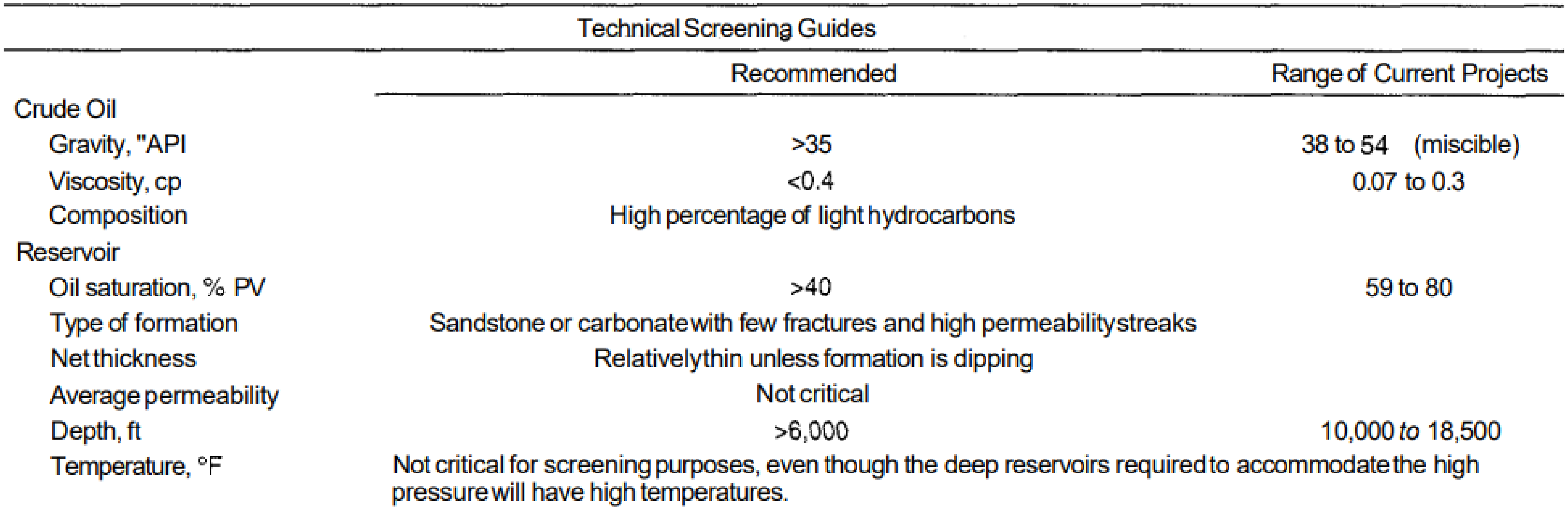
Nitrogen and Flue Gas Flooding

Mechanism

- Nitrogen and flue gas flooding recover oil by (1) vaporizing the lighter components of the crude oil and generating miscibility if the pressure is high enough; (2) providing a gas drive where a significant portion of the reservoir volume is filled with low-cost gases, and (3) enhancing gravity drainage in dipping reservoirs (miscible or immiscible).

Nitrogen and Flue Gas Flooding

Criteria



Technical Screening Guides

	Recommended	Range of Current Projects
Crude Oil		
Gravity, "API	>35	38 to 54 (miscible)
Viscosity, cp	<0.4	0.07 to 0.3
Composition	High percentage of light hydrocarbons	
Reservoir		
Oil saturation, % PV	>40	59 to 80
Type of formation	Sandstone or carbonate with few fractures and high permeability streaks	
Net thickness	Relatively thin unless formation is dipping	
Average permeability	Not critical	
Depth, ft	>6,000	10,000 *to* 18,500
Temperature, °F	Not critical for screening purposes, even though the deep reservoirs required to accommodate the high pressure will have high temperatures.	

Nitrogen and Flue Gas Flooding

Limitations

- Developed miscibility can only be achieved with light oils and at very high pressures; therefore, deep reservoirs are needed. A steeply dipping reservoir is desired to permit gravity stabilization of the displacement, which has an unfavorable mobility ratio. For miscible or immiscible enhanced gravity drainage, a dipping reservoir may be crucial to the success of the project.

Nitrogen and Flue Gas Flooding

Problems

- Viscous fingering results in poor vertical and horizontal sweep efficiency. The nonhydrocarbon gases must be separated from the saleable produced gas. Injection of flue gas has caused corrosion problems in the past. At present, nitrogen is being injected into large successful projects that formerly used flue gas.

Hydrocarbon Injection

Description

- Hydrocarbon-miscible flooding consists of injecting light hydrocarbons through the reservoir to form a miscible flood. Three different methods have been used. The first-contact miscible method uses about 5% PV slug of liquefied petroleum gas (LPG), such as propane, followed by natural gas or gas and water. A second method, called enriched (condensing) gas drive, consists of injecting a 10 to 20% PV slug of natural gas that is enriched with ethane through hexane, followed by lean gas (dry, mostly methane) and possibly water. The enriching components are transferred from the gas to the oil. The third and most common method, called high-pressure (vaporizing) gas drive, consists of injecting lean gas at high pressure to vaporize C2 through C6 components from the crude oil being displaced. A combination of condensing/vaporizing mechanisms also occurs at many reservoir conditions, even though we usually think that one process is dominant.

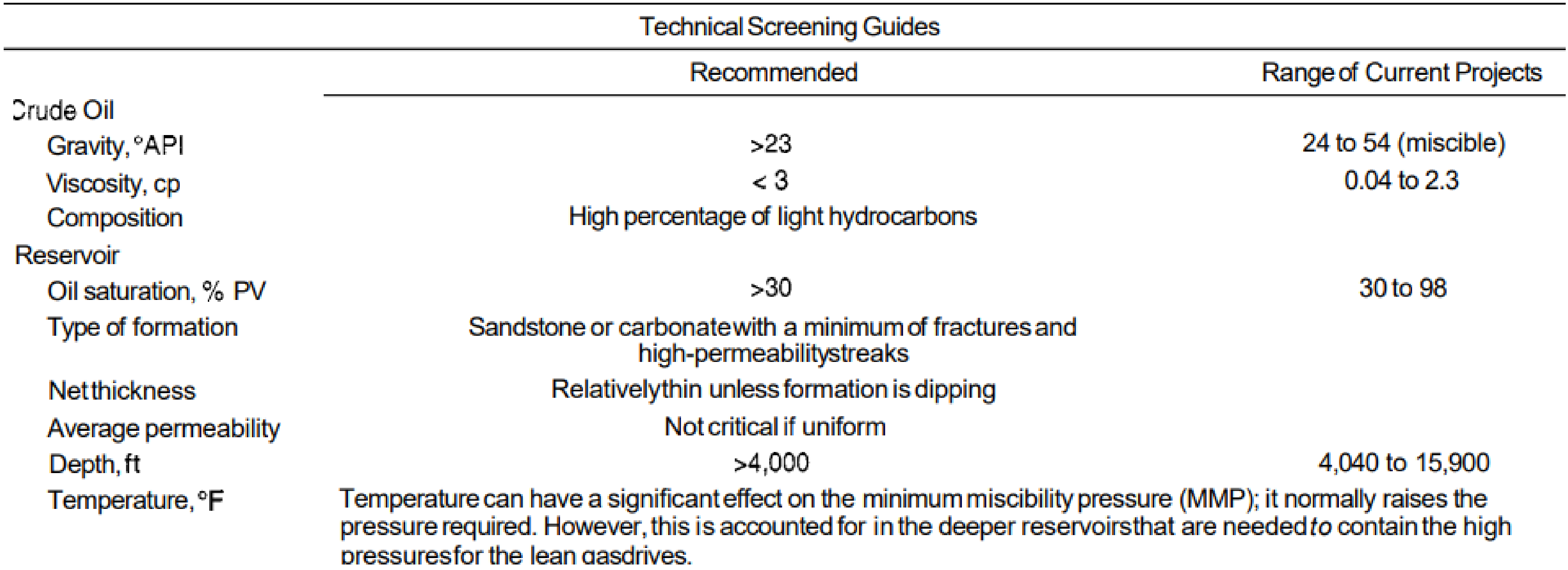
Hydrocarbon Injection

Mechanism

- Hydrocarbon miscible flooding recovers crude oil by (1) generating miscibility (in the condensing and vaporizing gas drive); (2) increasing the oil volume (swelling); (3) decreasing the oil viscosity; and (4) immiscible gas displacement, especially enhanced gravity drainage with the right reservoir conditions.

Hydrocarbon Injection

Criteria



Technical Screening Guides	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	>23	24 to 54 (miscible)
Viscosity, cp	< 3	0.04 to 2.3
Composition	High percentage of light hydrocarbons	
Reservoir		
Oil saturation, % PV	>30	30 to 98
Type of formation	Sandstone or carbonate with a minimum of fractures and high-permeability streaks	
Net thickness	Relatively thin unless formation is dipping	
Average permeability	Not critical if uniform	
Depth, ft	>4,000	4,040 to 15,900
Temperature, °F	Temperature can have a significant effect on the minimum miscibility pressure (MMP); it normally raises the pressure required. However, this is accounted for in the deeper reservoirs that are needed to contain the high pressures for the lean gas drives.	

Hydrocarbon Injection

Limitations

- The minimum depth is set by the pressure needed to maintain the generated miscibility. The required pressure ranges from about 1,200 psi for the LPG process to 4,000 to 5,000 psi for the high-pressure gas drive, depending on the oil. A steeply dipping formation is very desirable to permit some gravity stabilization of the displacement, which normally has an unfavorable mobility ratio.

Hydrocarbon Injection

Problems

- Viscous fingering results in poor vertical and horizontal sweep efficiency. Large quantities of valuable hydrocarbons are required. Solvent may be trapped and not recovered in the LPG method

CO_2 Injection

Description

- CO_2 flooding is carried out by injecting large quantities of CO_2 (30% or more of the hydrocarbon PV into the reservoir. Although CO_2 is not first-contact miscible with the crude oil, the CO_2 extracts the light-to-intermediate components from the oil and, if the pressure is high enough, develops miscibility to displace the crude oil from the reservoir (MMP). Immiscible displacements are less effective, but they recover oil better than waterflooding.

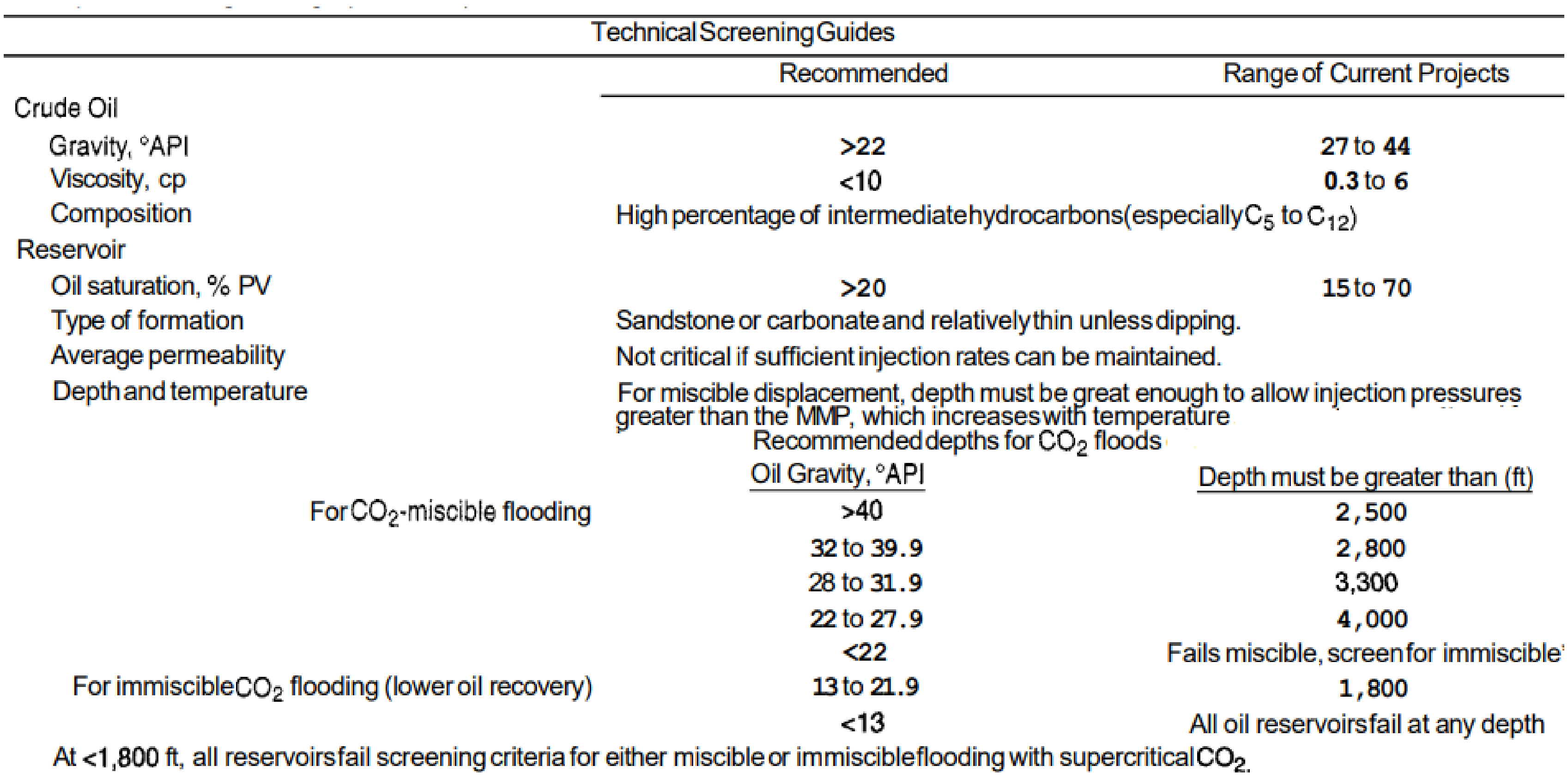
CO_2 Injection

Mechanisms

- CO_2 recovers crude oil by (1) swelling the crude oil (CO_2 is very soluble in high gravity oils); (2) lowering the viscosity of the oil (much more effectively than N_2 or CH_4); (3) lowering the interfacial tension between the oil and the CO_2 /oil phase in the near-miscible regions; and (4) generation of miscibility when pressure is high enough.

CO_2 Injection

Criteria



Technical Screening Guides

	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	>22	27 to 44
Viscosity, cp	<10	0.3 to 6
Composition	High percentage of intermediate hydrocarbons (especially C_5 to C_{12})	
Reservoir		
Oil saturation, % PV	>20	15 to 70
Type of formation	Sandstone or carbonate and relatively thin unless dipping.	
Average permeability	Not critical if sufficient injection rates can be maintained.	
Depth and temperature	For miscible displacement, depth must be great enough to allow injection pressures greater than the MMP, which increases with temperature	
	Recommended depths for CO_2 floods	
	Oil Gravity, °API	Depth must be greater than (ft)
For CO_2-miscible flooding	>40	2,500
	32 to 39.9	2,800
	28 to 31.9	3,300
	22 to 27.9	4,000
	<22	Fails miscible, screen for immiscible
For immiscible CO_2 flooding (lower oil recovery)	13 to 21.9	1,800
	<13	All oil reservoirs fail at any depth

At <1,800 ft, all reservoirs fail screening criteria for either miscible or immiscible flooding with supercritical CO_2.

CO_2 Injection

Limitations

- A good source of low-cost CO_2 is required.

Problems

- Corrosion can cause problems, especially if there is early breakthrough of CO_2 in producing wells.

Alkaline Injection

Description

- During alkaline flooding, the alkaline solution and organic acids present in the crude oil react to form natural surfactants *in situ*, which cause the reduction of IFT between the brine and oil.

- It is the cheapest method among the chemical operations.

Alkaline Injection

Limitations/Problems

- It has very little application since it has very limited working criteria (acidic oil, sandstone formation, etc.).

- Scale formation is a serious issue during alkaline flooding. Furthermore, the low viscosity of the alkaline solution is associated with the occurrence of unfavourable fingering and poor volumetric sweep efficiency

Polymer Injection

Description

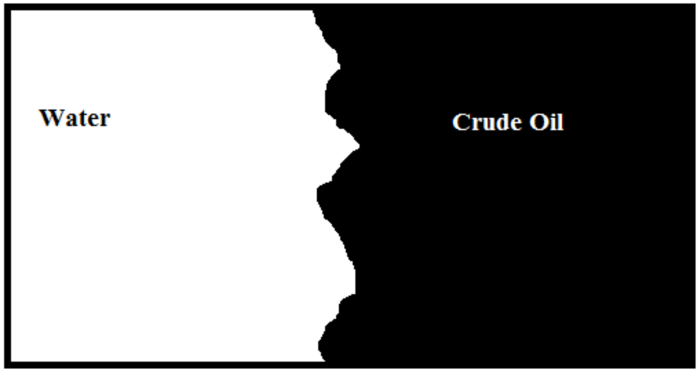
- The objective of polymer flooding is to provide better displacement and volumetric sweep efficiencies during a waterflood. In polymer flooding, certain high-molecular-weight polymers (typically polyacrylamide or xanthan) are dissolved in the injection water to decrease water mobility. Polymer concentrations from 250 to 2,000 mg/L are used; properly sized treatments may require 25 to 60% reservoir PV.

Polymer Injection

Mechanisms

- Polymers improve recovery by (1) increasing the viscosity of water; (2) decreasing the mobility of water; and (3) contacting a larger volume of the reservoir.

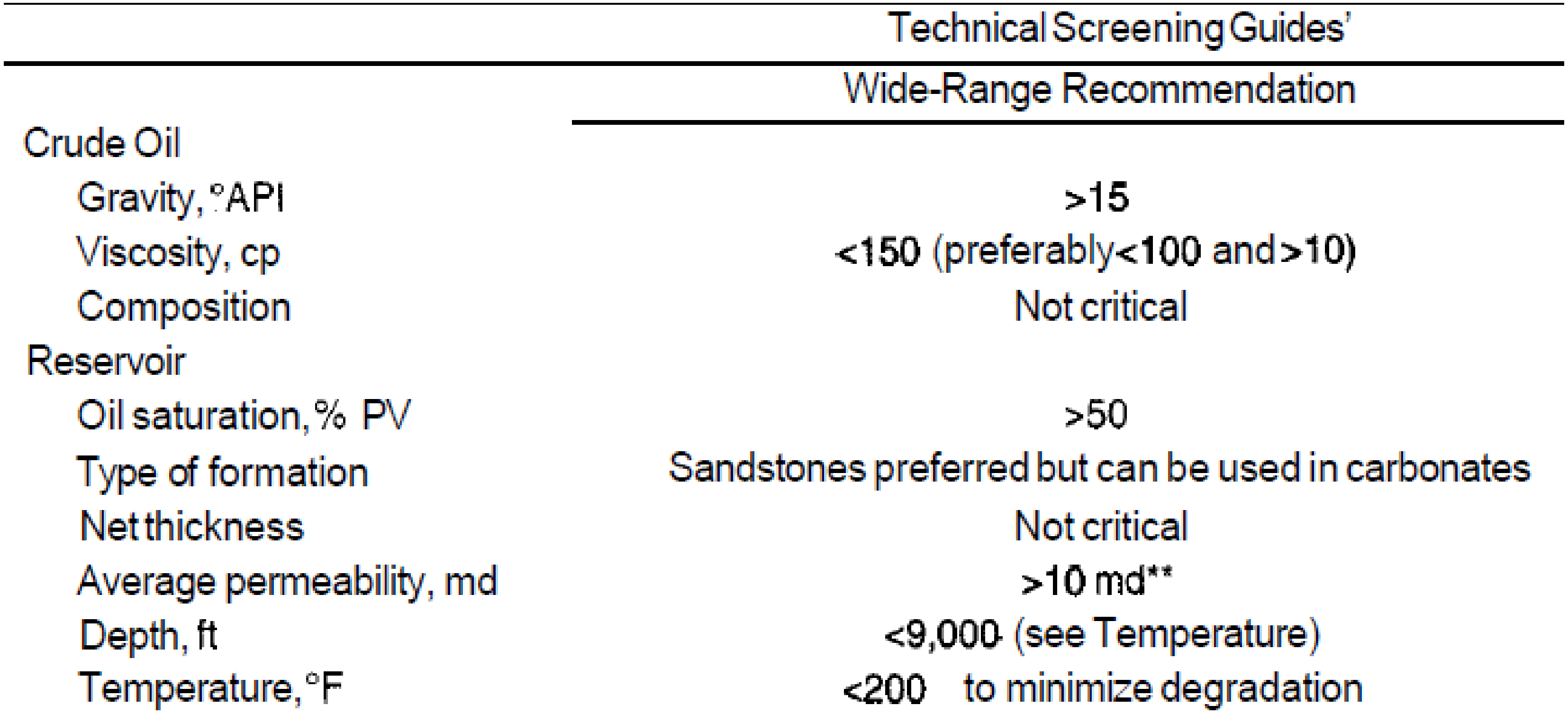
Viscous Fingering



After Polymer Injection

Polymer Injection

Criteria



	Technical Screening Guides'
	Wide-Range Recommendation
Crude Oil	
Gravity, °API	>15
Viscosity, cp	<150 (preferably<100 and>10)
Composition	Not critical
Reservoir	
Oil saturation, % PV	>50
Type of formation	Sandstones preferred but can be used in carbonates
Net thickness	Not critical
Average permeability, md	>10 md**
Depth, ft	<9,000 (see Temperature)
Temperature, °F	<200 to minimize degradation

Polymer Injection

Limitations/Problems

- In reservoirs where the rock permeability is less than 50 md, the polymer may sweep only fractures effectively unless the polymer molecular weight is sufficiently low.

Micellar/Polymer, ASP, Alkaline Injection

Description

- Classic micellar/polymer flooding consists of injecting a slug that contains water, surfactant, polymer, electrolyte (salt), sometimes a cosolvent (alcohol), and possibly a hydrocarbon (oil). The size of the slug is often 5 to 15% PV for a high-surfactant-concentration system and 15 to 50% PV for low concentrations. The surfactant slug is followed by polymer-thickened water. The polymer concentration often ranges from 500 to 2,000 mg/L, and the volume of polymer solution injected may be 50% PV or more.
- ASP flooding is similar except that much of the surfactant is replaced by low-cost alkali so the slugs can be much larger but overall cost is lower and polymer is usually incorporated in the larger, dilute slug. For alkaline flooding much of the injection water was treated with low concentrations of the alkaline agent and the surfactants were generated in situ by interaction with oil and rock.

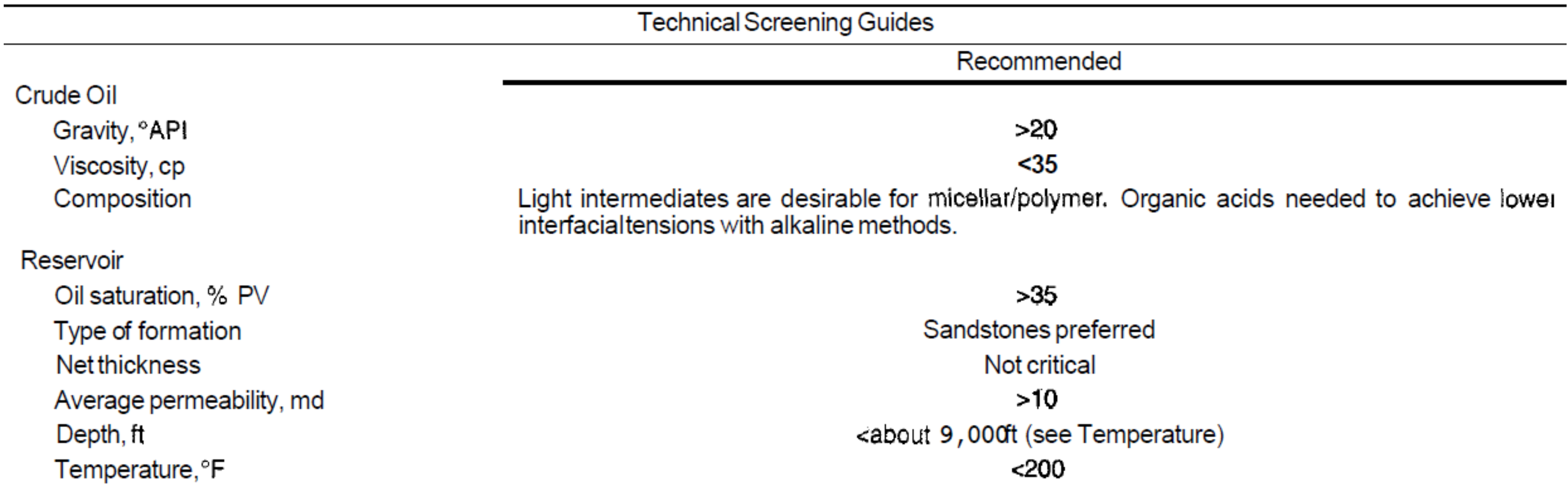
Micellar/Polymer, ASP, Alkaline Injection

Mechanism

- All surfactant and alkaline flooding methods recover oil by **(1)** lowering the interfacial tension between oil and water; **(2)** solubilization of oil in some micellar systems; **(3)** emulsification of oil and water, especially in the alkaline methods; **(4)** wettability alteration (in the alkaline methods); and **(5)** mobility enhancement.

Micellar/Polymer, ASP, Alkaline Injection

Criteria



Technical Screening Guides

	Recommended
Crude Oil	
Gravity, °API	>20
Viscosity, cp	<35
Composition	Light intermediates are desirable for micellar/polymer. Organic acids needed to achieve lower interfacial tensions with alkaline methods.
Reservoir	
Oil saturation, % PV	>35
Type of formation	Sandstones preferred
Net thickness	Not critical
Average permeability, md	>10
Depth, ft	<about 9,000ft (see Temperature)
Temperature, °F	<200

Micellar/Polymer, ASP, Alkaline Injection

Limitations

- An areal sweep of more than 50% on waterflood is desired. Relatively homogeneous formation is preferred. High amounts of anhydrite, gypsum, or clays are undesirable. Available systems provide optimum behavior over a narrow set of conditions. With commercially available surfactants, formation-water chlorides should be <20,000 ppm and divalent ions (Ca++ and Mg++) <500 ppm.

Micellar/Polymer, ASP, Alkaline Injection

Problems

- Complex and expensive systems. Possibility of chromatographic separation of chemicals in reservoir. High adsorption of surfactant. Interactions between surfactant and polymer. Degradation of chemicals at high temperature.

In-Situ Combustion

Description

- In-situ combustion or fireflooding involves starting a fire in the reservoir and injecting air to sustain the burning of some of the crude oil. The most common technique is forward combustion in which the reservoir is ignited in an injection well, and air is injected to propagate the combustion front away from the well. One of the variations of this technique is a combination of forward combustion and waterflooding. A second technique is reverse combustion in which a fire is started in a well that will eventually become a producing well, and air injection is then switched to adjacent wells; however, no successful field trials have been completed for reverse combustion.

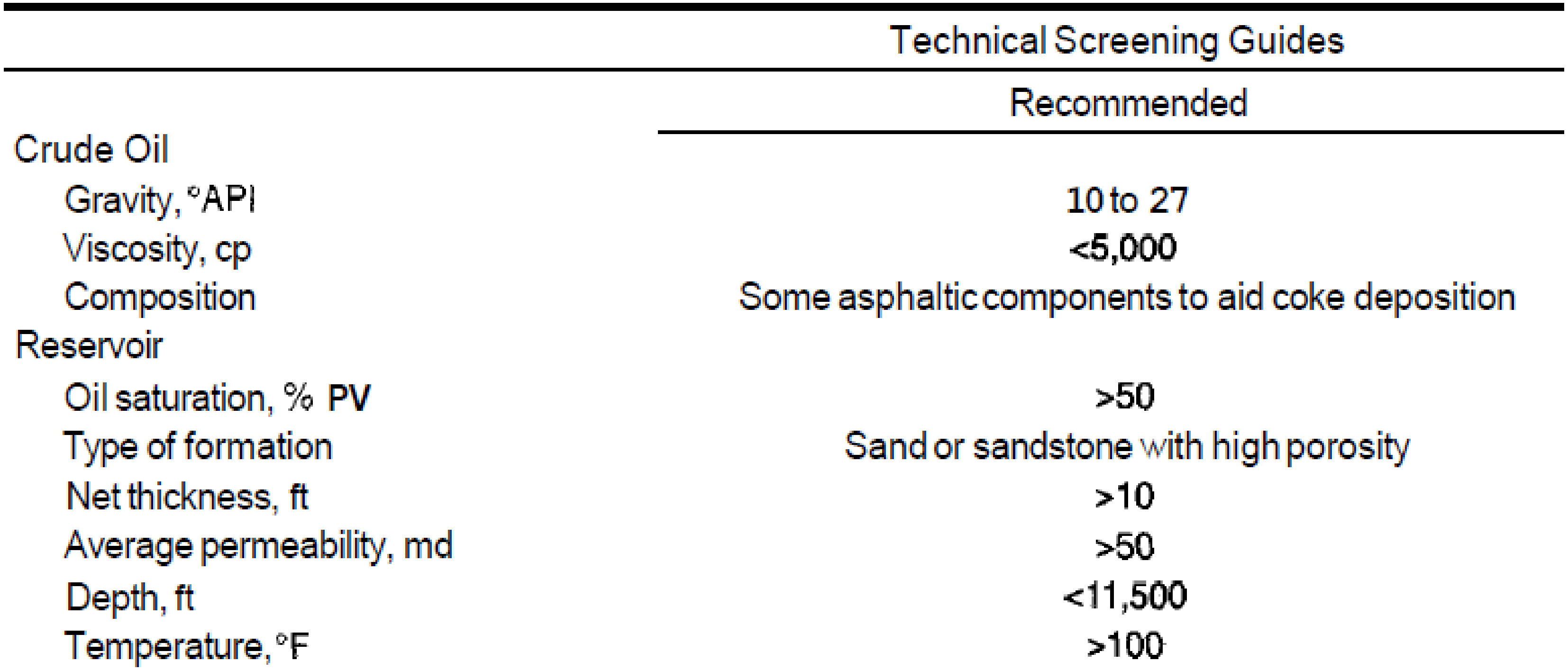
In-Situ Combustion

Mechanisms

- In-situ combustion recovers crude oil by **(1)** the application of heat which is transferred downstream by conduction and convection, thus lowering the viscosity of the oil; **(2)** the products of steam distillation and thermal cracking that are carried forward to mix with and upgrade the crude; **(3)** burning coke that is produced from the heavy ends of the oil; and (4) the pressure supplied to the reservoir by injected air

In-Situ Combustion

Criteria



	Technical Screening Guides
	Recommended
Crude Oil	
Gravity, °API	10 to 27
Viscosity, cp	<5,000
Composition	Some asphaltic components to aid coke deposition
Reservoir	
Oil saturation, % PV	>50
Type of formation	Sand or sandstone with high porosity
Net thickness, ft	>10
Average permeability, md	>50
Depth, ft	<11,500
Temperature, °F	>100

In-Situ Combustion

Limitations

- If sufficient coke is not deposited from the oil being burned, the combustion process will not be sustained; this prevents the application for high-gravity paraffinic oils. If excessive coke is deposited, the rate of advance of the combustion zone will be slow and the quantity of air required to sustain combustion will be high. Oil saturation and porosity must be high to minimize heat loss to rock. Process tends to sweep through upper part of reservoir so that sweep efficiency is poor in thick formations.

In-Situ Combustion

Problems

- Adverse mobility ratio. Early breakthrough of the combustion front. Complex process that requires large capital investment and is difficult to control. Produced flue gases can present environmental problems. Operational problems, such as severe corrosion caused by low-pH hot water, serious oil/water emulsions, increased sand production, deposition of carbon or wax, and pipe failures in the producing wells as a result of the very high temperatures.

Steam Flooding

Description

- The steamdrive process or steamflooding involves continuous injection of about 80% quality steam to displace crude oil toward producing wells. Normal practice is to precede and accompany the steamdrive by a cyclic steam stimulation of the producing wells (called huff ’n’ puff).

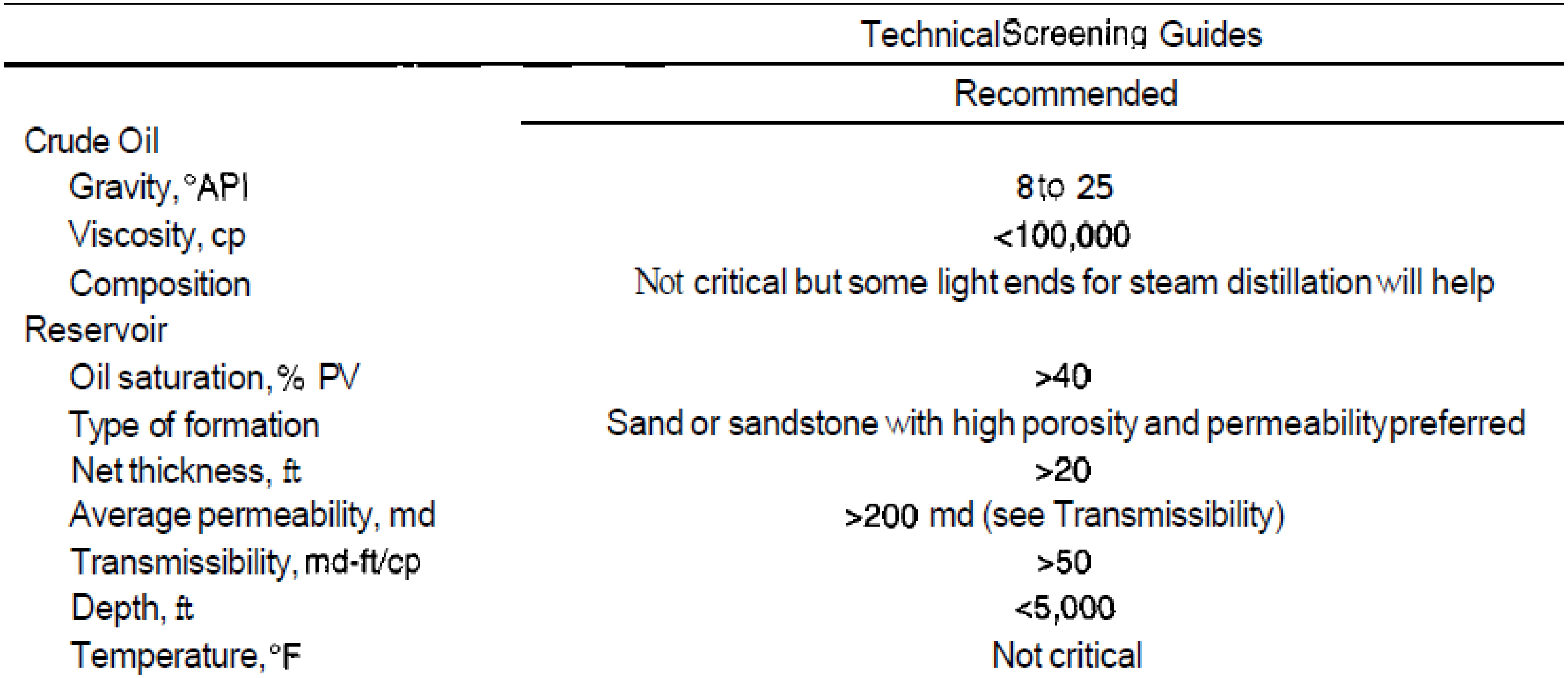
Steam Flooding

Mechanisms

- Steam recovers crude oil by **(1)** heating the crude oil and reducing its viscosity; **(2)** supplying the pressure to drive oil to the producing well; and **(3)** steam distillation, especially in light crude oils

Steam Flooding

Criteria



	Technical Screening Guides
	Recommended
Crude Oil	
Gravity, °API	8 to 25
Viscosity, cp	<100,000
Composition	Not critical but some light ends for steam distillation will help
Reservoir	
Oil saturation, % PV	>40
Type of formation	Sand or sandstone with high porosity and permeability preferred
Net thickness, ft	>20
Average permeability, md	>200 md (see Transmissibility)
Transmissibility, md-ft/cp	>50
Depth, ft	<5,000
Temperature, °F	Not critical

Steam Flooding

Limitations/Problems

- Oil saturations must be quite high, and the pay zone should be more than 20 ft thick to minimize heat losses to adjacent formations. Lighter, less-viscous crude oils can be steamflooded but normally will not be if the reservoir responds to an ordinary waterflood. Steamflooding is primarily applicable to viscous oils in massive, high-permeability sandstones or unconsolidated sands. Because of excess heat losses in the wellbore, steamflooded reservoirs should be as shallow as possible as long as pressure for sufficient injection rates can be maintained. Steamflooding is not normally used in carbonate reservoirs. Because about one-third of the additional oil recovered is consumed to generate the required steam, the cost per incremental barrel of oil is high. A low percentage of water-sensitive clays is desired for good injectivity.

Hot Water Injection

Description

- A method of thermal recovery in which hot water is injected into a reservoir through specially distributed injection wells. Hot waterflooding reduces the viscosity of the crude oil, allowing it to move more easily toward production wells. Hot waterflooding, is typically less effective than a steam-injection process because water has lower heat content than steam.
- It is an inefficient operation with high heat losses. It is applied in areas close to the surface.
- It is rarely performed.

Hot Water Injection

Limitations/Problems

- The choice of the water-flood parameters: the temperature of injected water, slug volume, injection rate, and starting time, is dictated by the specific geological and physical characteristics of the particular oilfield, after which a hydrodynamic estimate of the efficiency of hot water-flooding in comparison with other methods of enhanced oil recovery must be made.
- Hot water-flooding is particularly effective in the development of fields of high viscosity oils which contain large quantities of paraffins and resinous asphaltene substances.

Smart Water (Low Salinity) Injection

Description

- Decreasing the injection water’s salinity by reducing the total dissolved solids (TDS) has been proved to increase oil recovery.

Smart Water (Low Salinity) Injection

Mechanisms

- Favorable wettability alteration in sandstone cores occurs when the injection water's TDS is reduced below 6,000 ppm.

- Interfacial tension is reduced in carbonate cores when the injection water's TDS is reduced from 214,943 ppm to 52,346 ppm.

Smart Water (Low Salinity) Injection

Limitations/Problems

- The mechanism of LSWF oil recovery remains unclear, despite several theories.
- The availability of low-salinity water sources is a limiting factor in LSWF's application.
- Maximized oil recovery during LSFW requires optimal salinity to effectively alter wettability without decreasing reservoir permeability.

Microbial Injection

Description

- Microorganisms and nutrients are injected into the reservoir, where the microorganism(s) multiply and their metabolic products, such as polymers, surfactants, gases, and acids, improve oil recovery.

Microbial Injection

Mechanisms

- Increased reservoir pressure as a result of microbial gas generation.
- Reduced oil viscosity.
- Modified permeability due to acidic dissolution or plugging.
- Decreased IFT resulting from microbial biosurfactant generation and a reduced population of sulfate-reducing bacteria.

Microbial Injection

Limitations/Problems

- The majority of successful MEOR projects have been applied to reservoirs with temperatures below 55°C.
- MEOR projects are suited for low-production-rate and high-water-cut reservoirs.
- In the past years, the success rate of MEOR projects has been about 60%.
- Surfactant adsorption to the reservoir rock and biodegradation adversely impact MEOR's performance.
- Water salinity could effect microbial activity negatively

Class Work

Field A:

- Depth > 2000 m.
- Carbonate
- 15 API gravity
- Possible EOR Methods?

Class Work

Field B:

- Depth = 750 m.
- Sandstone
- 15 API gravity
- High viscous oil (> 5000 cp)
- High permeable reservoir (> 100 md)
- Possible EOR Methods?

Class Work

Field C:

- Depth = 1750 m.
- Sandstone
- 25 API gravity
- Low viscous oil (20 cp)
- Possible EOR Methods?

Enhanced Oil Recovery

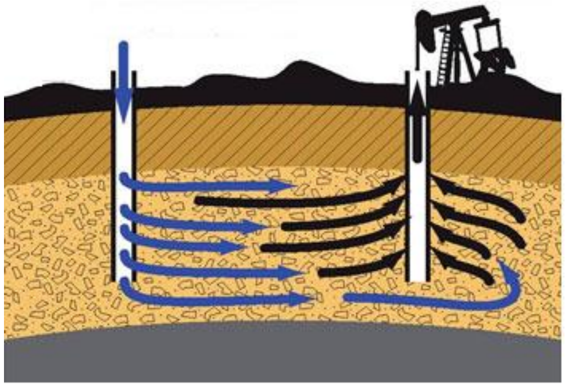
References:

- Taber J.J. Martin F.D., Seright R.S., EOR Screening Criteria Revisited – Part 2: Applications and Impact of Oil Prices SPE, 1997.

- ÖZGÜR, E., "The role of enhanced oil recovery in the upstream petroleum sector, a Turkey case", Bulletin of the Mineral Research and Exploration, Vol : 158 pg. 291-297, 2019.

PNGE 443
Enhanced Oil Recovery

Chapter 3
Review of Rock and Fluid Properties, Microscopic and Macroscopic Properties



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Reservoir Parameters for EOR

- Reservoir geometry
- Fluid properties
- Reservoir depth
- Lithology and rock properties
- Fluid saturations

Reservoir Parameters for EOR

Overall Displacement Efficiency (E)
$E = E_d \times E_v$

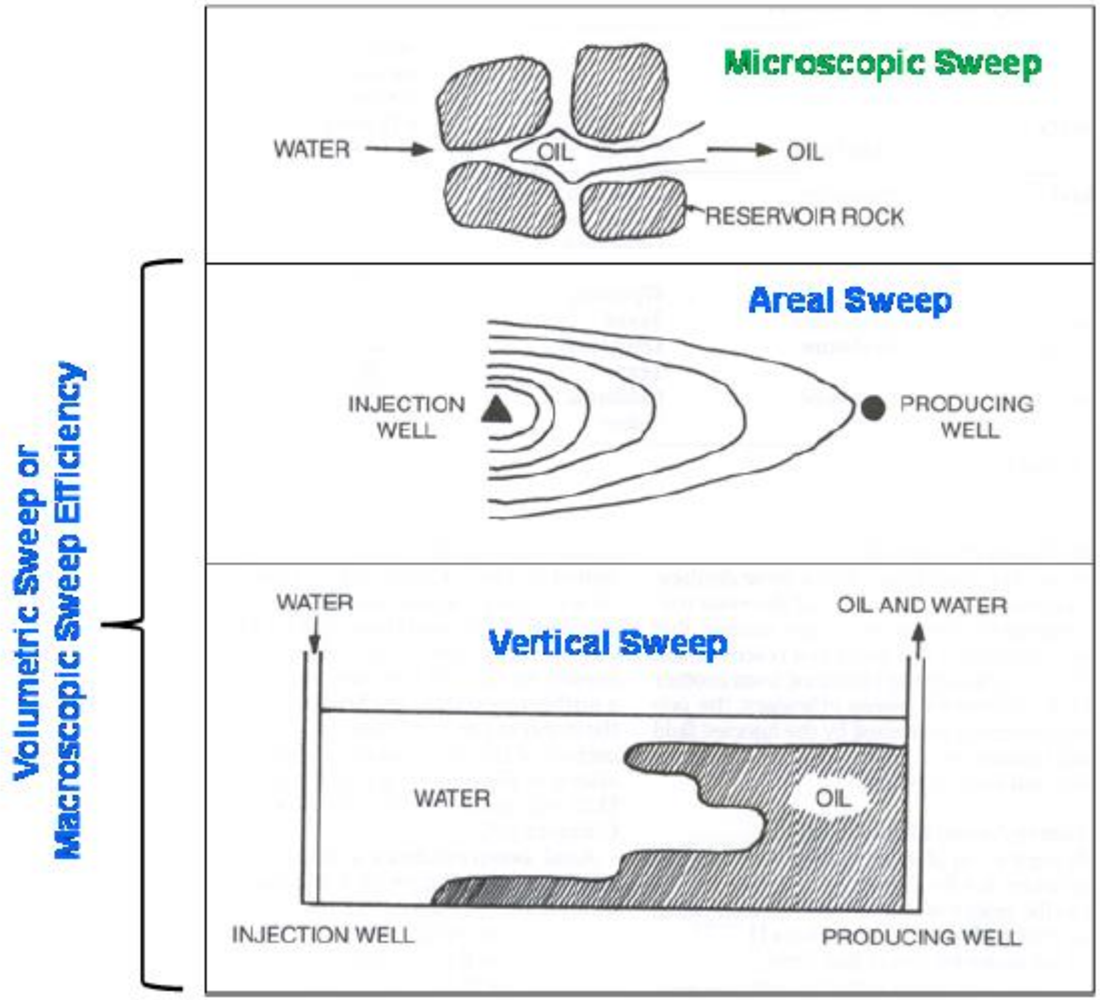
Microscopic Displacement Efficiency (E_d)

- Rock Wettability
- Relative Permeability
- Interfacial Tension
- Capillary Pressure

Macroscopic Displacement Efficiency (E_v)

- Fluid mobilities
- Areal heterogeneity (k, h, Swc, ϕ, Fault, Boundary conditions)
- Gravity and viscous forces
- Total volume of fluid injected
- Injection/production well pattern

Reservoir Parameters for EOR



Microscopic Displacement

- Rock Wettability
- Relative Permeability
- Interfacial Tension
- Capillary Pressure

Microscopic displacement efficiency is a measure of mobilization of residual oil by displacing fluid. It is controlled by factors such as rock wettability, relative permeability, IFT and capillary force. A decrease in any of these factors can increase the displacement efficiency.

Interfacial Tension

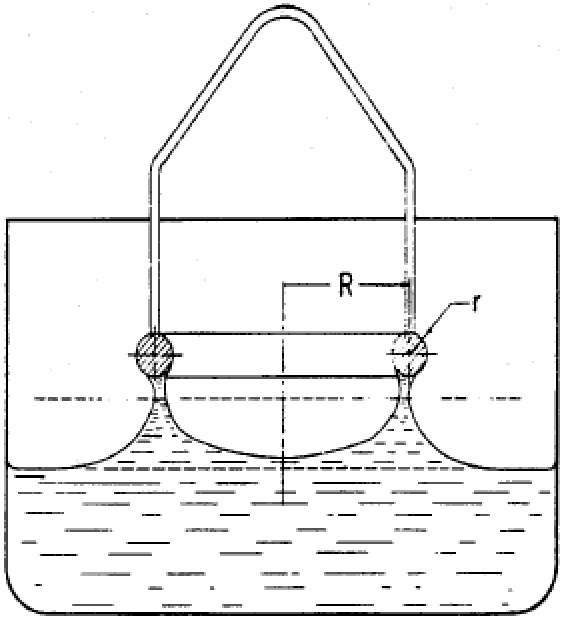
- The IFT is a fundamental thermodynamic property of an interface. It is defined as the energy required to increase the size of the interface between two adjacent phases which do not mix completely with one another. The methods of measuring IFT's include a ring tensiometer, sessile drop and spinning drop techniques.
- Surface tension is defined between a liquid and its vapor (or air).
- The surface tension of water in contact with its vapor at room temperature is approximately 72 dynes/cm. IFTs between water and pure hydrocarbons are approximately 30 to 50 dynes/cm at room temperature.
- IFTs and surface tensions are relatively strong functions of temperature.
- IFT is a measure of miscibility. The two phases approach miscibility with the lower IFT. Low IFT's are observed in systems containing alcohols and surfactants.

Interfacial Tension

- Interfacial surface tension is proportional to surface tension force

- If we denote the interfacial tension by σ,and *F* is the minimum force required to raise the ring through the liquid surface,

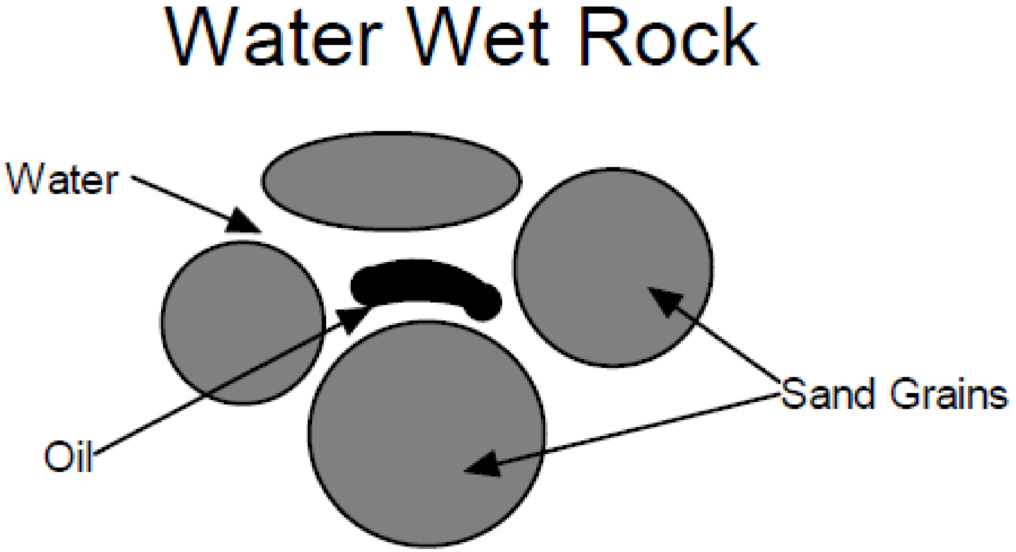
$$\sigma = \frac{F}{(2\pi R)}$$



Wettability

- Fluid distributions in porous media are affected not only by the forces at fluid/fluid interfaces, but also by forces at fluid/solid interfaces. Wettability is defined as when a solid surface is contacted with two immiscible fluids, the tendency of one phase to spread on or adhere to a solid surface more compared to the other phase. This phase is identified as the wetting phase while the other phase is the nonwetting phase.
- Rock wettability affects the nature of fluid saturations and the general relative permeability characteristics of a fluid/rock system.
- Wettability is explained quantitatively by examining the force balances between two immiscible fluids and the solid at the contact line.

Wettability



- It is very difficult to measure the contact angle for field applications; to do so, we would need a clean even (flat) surface obtained from the reservoir rock.

Wettability

- To facilitate oil flow, it is better to have water-wet rock than oil-wet rock.

– When water "sticks" to the rock it spreads over the rock surface and leaves the oil in channels surrounded by water.

– The friction between flowing oil and the surrounding water "cushion" is much less than the friction between oil and rock, so oil flows easily.

- Conversely, if the rock is preferentially oil-wet, it is much more difficult to displace oil from the reservoir. Residual oil saturation is higher.

Wettability

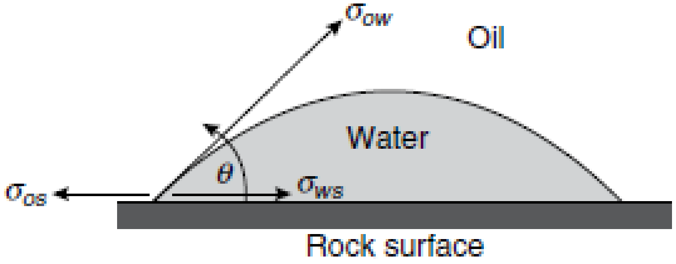
- Young equation represents the force balance in the direction parallel to the rock surface;

$$\sigma_{os} - \sigma_{ws} = \sigma_{ow} \cos\theta \qquad (1)$$

σ_{os}, σ_{ws}, σ_{ow} = IFTs between oil and solid, water and solid, oil and water, respectively, dynes/cm

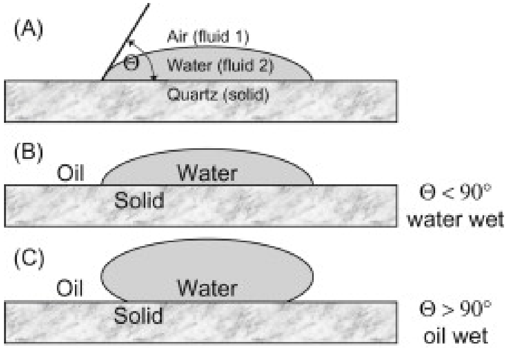
θ = Contact angle, measured through the dense phase.

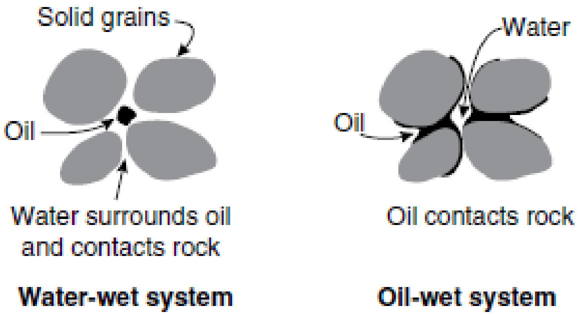
- Neither σ_{os} or σ_{ws} has ever been measured. Consequently, θ is the principal measure of wettability for a smooth, homogeneous surface.



Wettability

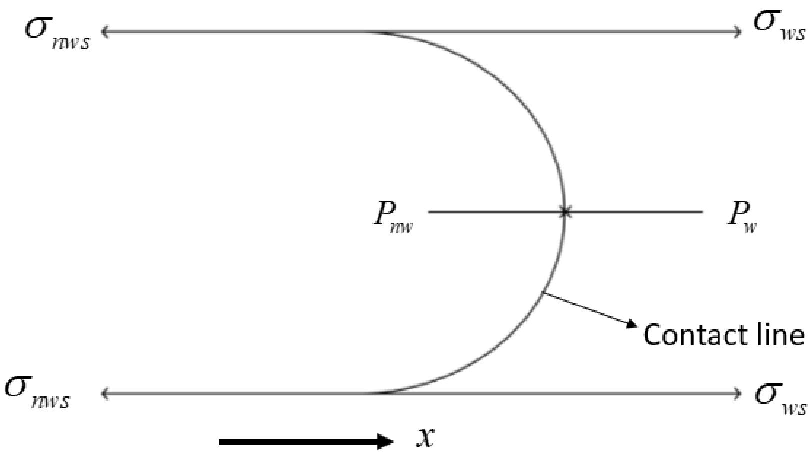
- Wetting indicates one phase attract more to solid surface compared to other phase. Different wettability conditions may occur depending on crude oil characteristic, mineralogy of the surface or combination of these.





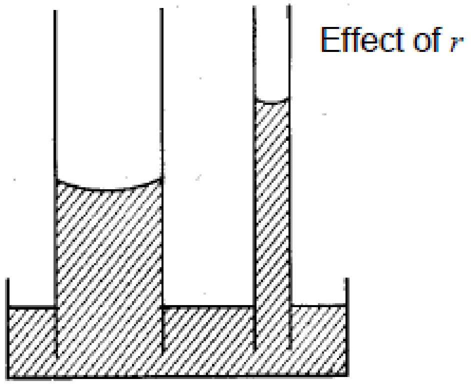
Capillary Pressure

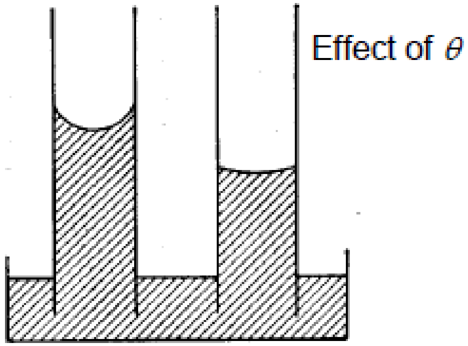
- Because interfaces are in tension in the systems described, a pressure difference exists across the interface. This pressure is called capillary pressure. The concept of capillary pressure as a characteristic of a porous rock evolved from the presentation of capillary phenomena in capillary tubes. Pores in reservoir rocks are analogous to capillary tubes.
- The capillary phenomena are predictable from the analysis of the forces at the contact line between the interface and the solid surface.



Capillary Pressure

- Capillary pressure must be equal to gravitational forces if fluids are in equilibrium and not flowing.
- Capillary pressure is a function of adhesion tension (or IFT) and inversely proportional to the radius of the tube.
- The greater the adhesion tension (or IFT), the greater the equilibrium height.





Capillary Pressure

- At equilibrium, the components of the forces acting in the horizontal direction is zero ($\sum F_x = 0$).

(Internal pressure-External pressure)*Cross-sectional area=Interfacial tension*Circumference

$$P_{nw}\left(\pi r^2\right)+\sigma_{ws}\left(2\pi r\right)-P_w\left(\pi r^2\right)-\sigma_{nws}\left(2\pi r\right)=0 \qquad (2)$$

or

$$P_{nw}-P_w=\frac{2\left(\sigma_{nws}-\sigma_{ws}\right)}{r} \qquad (3)$$

Using Eq. (1), Eq. (3) becomes;

$$P_{nw}-P_w=\frac{2\sigma_{nww}\cos\theta}{r} \qquad (4)$$

Capillary Pressure

- The pressure difference ($P_{nw} - P_w$) is defined as capillary pressure (P_c).

$$P_c = P_{nw} - P_w$$

- Laplace developed a generalized expression for the pressure difference across the interface;

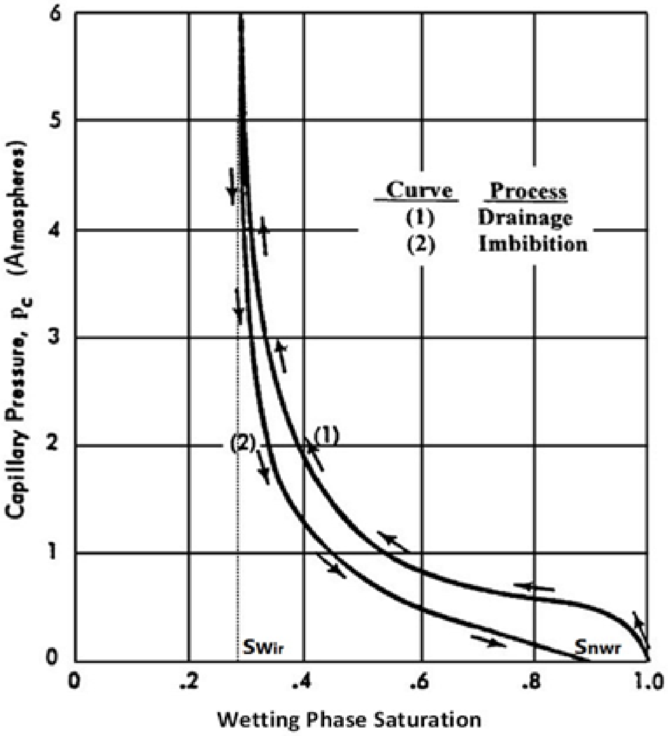
$$P_{nw} - P_w = \sigma_{ow}\left(\frac{1}{r_1} + \frac{1}{r_2}\right) \qquad (5)$$

where r_1^* and r_2^* are the radii of curvature for the interface.

- If the radii of the curvature are on the same side of the interface, as in the capillary tube, both have positive values. Otherwise, the smaller radius is positive and the larger radius is negative. r_1 and r_2 are equal to $r/\cos\theta$ for a uniform, smoothing capillary tube of radius r.

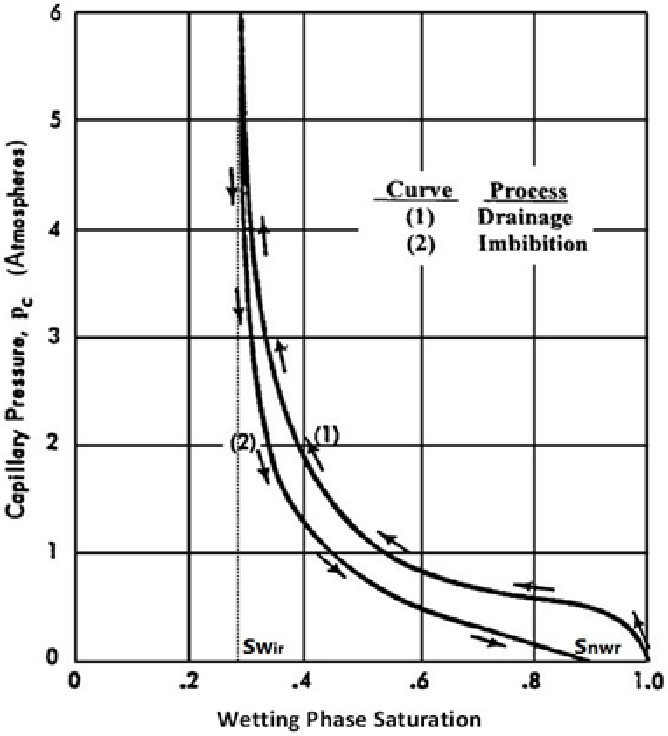
Capillary Pressure

- The displacement of the wetting fluid by a non-wetting fluid is referred to as drainage process and resulting curve is drainage capillary pressure curve.
- The displacement of a non-wetting fluid by a wetting fluid is referred to as imbibition process and the resulting curve is imbibition capillary pressure curve.
- The residual (or irreducible) saturation of the wetting fluid (S_{wir}) remains in the drainage process and residual saturation of non-wetting fluid (S_{nwr}) remains in imbibition process on the inner walls of the capillaries.

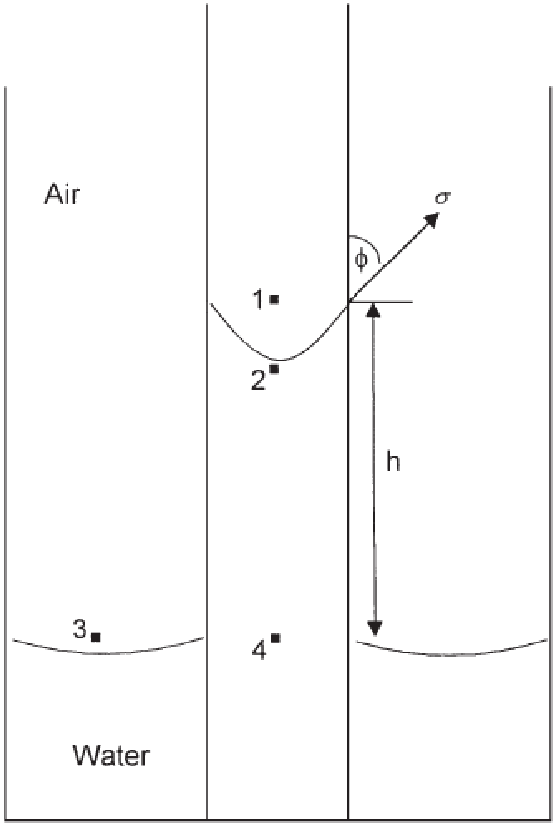


Capillary Pressure

- The drainage and imbibition plots are not same due to the hysteresis in contact angle (advancing and receding contact angles of fluid interfaces on solids). When the water saturation has risen to its maximum value S_w=1−S_{or}, the capillary pressure is zero. At this point the residual oil saturation, S_{or}, cannot be reduced, irrespective of the pressure difference applied between the water and oil.
- The capillary pressure curve can also be interpreted in terms of elevation of a plane constant water saturation above the level at which P_c=0.



Capillary Pressure



- The pressure difference across the interface suggests that

$$P_c = P_1 - P_2 \tag{6}$$

- The pressure at Point 4 is;

$$P_4 = P_2 + \rho_w gh \tag{7}$$

- The pressure at Point 3 is;

$$P_3 = P_1 + \rho_{air} gh \tag{8}$$

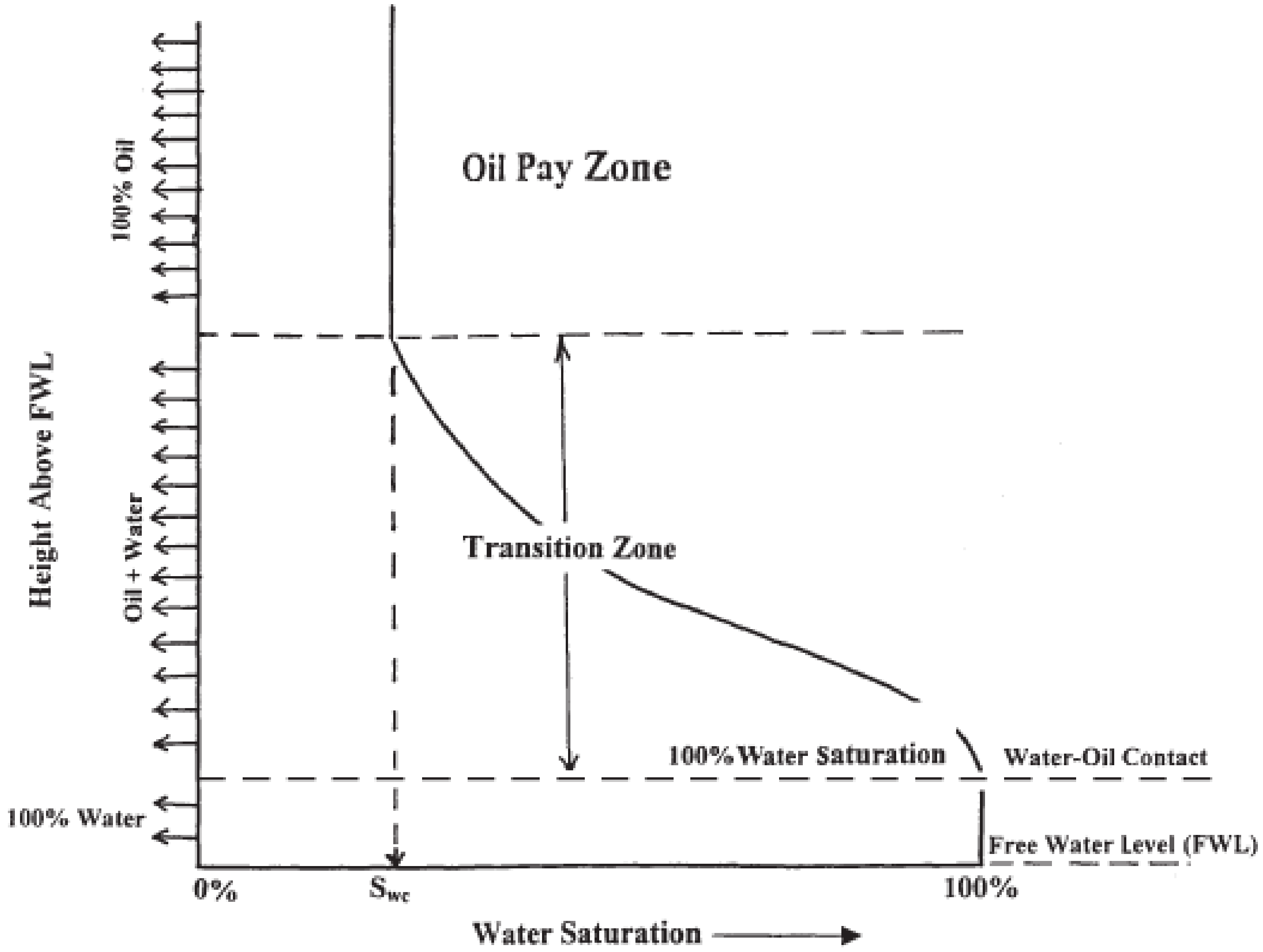
- By subtracting Eq. (7) from Eq. (8), we get P_c;

$$P_c = gh\left(\rho_w - \rho_{air}\right) = gh\Delta\rho \tag{9}$$

- Rearranging Eq. (9);

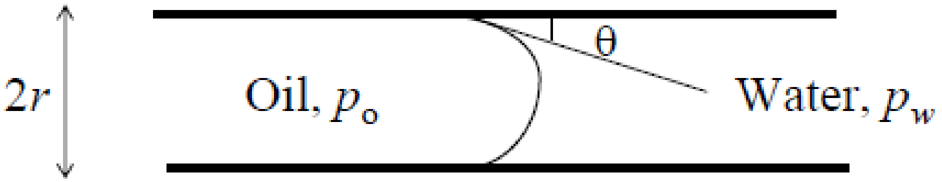
$$h = \frac{P_c}{g\Delta\rho}$$

Capillary Pressure



Class Example-1

- Consider a horizontal capillary tube of radius r = 10 μm (1 micrometer = 10^{-6} meters) as shown below, containing both oil and water (water wet). Both phases are stationary.



Given data: $p_o = 10^5$ pa (=100 kpa = 14.5 psi), θ = 30°, IFT = σ_{ow} = 30 dynes/cm (=30 mN/m = 30×10^{-3} N/m).

What is the value of water phase pressure, p_w?

Class Example-1 - Solution

Recall that the capillary pressure is given by

$$p_c = p_o - p_w = \frac{2\sigma_{ow}\cos\theta}{r}$$

Rearrange above equation for p_w and then use the data values given (make sure that we use consistent units)

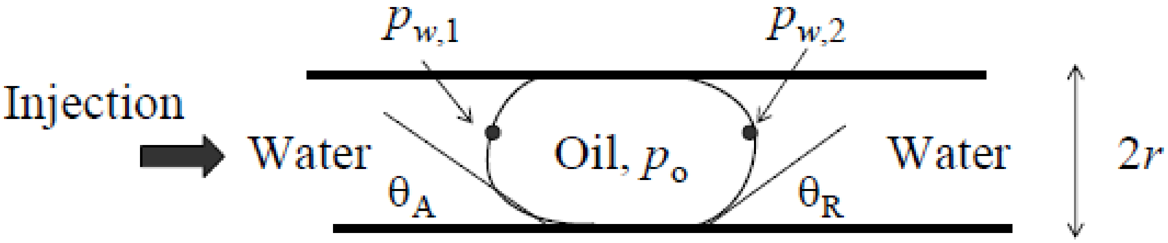
$$p_w = p_o - p_c = \frac{2\sigma_{ow}\cos\theta}{r}$$

$$p_w = 100000 \text{ pa} - \frac{2(30\times10^{-3}\text{ N/m})\cos 30}{10\times10^{-6}\text{m}}$$

$$= 94804 \text{ pa } (= 94.8 \text{ kpa} = 13.75 \text{ psi})$$

Class Example-2

- Consider an oil blob confined in a capillary tube of 10 μm radius (see below figure). The tube is wet by water. The oil blob is stationary. What is the minimum pressure required to move the oil blob?



Given data: $\theta_A = 30°$, $\theta_R = 10°$ IFT = σ_{ow} = 30 dynes/cm (=30 mN/m = 30×10^{-3} N/m), $R_1 = R_2 = r$

Class Example-2 - Solution

- Here, θ_A is called advancing angle, while θ_R is called receding angle. At the interfaces as indicated as points 1 and 2, we can write the following two equations:

$$p_{c,1} = p_{o,1} - p_{w,1} = \frac{2\sigma_{ow}\cos\theta_A}{r}$$

$$p_{c,2} = p_{o,2} - p_{w,2} = \frac{2\sigma_{ow}\cos\theta_R}{r}$$

Here, r is the radius of the tube.

- For oil blob to be stationary,

$$p_{o,1} = p_{o,2}$$

- It follows from previous equations that

$$p_{w,1} + \frac{2\sigma_{ow}\cos\theta_A}{r} = p_{w,2} + \frac{2\sigma_{ow}\cos\theta_R}{r}$$

or

$$\Delta p_c = p_{w,1} - p_{w,2} = \frac{2\sigma_{ow}\left(\cos\theta_R - \cos\theta_A\right)}{r}$$

Class Example-2 - Solution

- Using the parameter values given

$$\Delta p_c = \frac{2(30\times10^{-3}\ \mathrm{N/m})}{10\times10^{-6}\ \mathrm{m}}(\cos 10 - \cos 30)$$

$$\Delta p_c = 712.69\ \mathrm{pa}\ (0.713\ \mathrm{kpa} = 71\ \mathrm{N/m^2} = 0.1\ \mathrm{psi})$$

- We should exceed at least 0.71 kpa to move the oil by injecting water.

Residual Saturation

- Residual oil saturation shows the remaining trapped oil in a reservoir rock after a displacement process. It depends on several variables which are wettability, pore size distribution, microscopic heterogeneity of rock and the properties of displacing fluid.
- What can be done to improve the recovery?
- Let’s examine some of the dimensionless groups that affect flow mechanism in the reservoir. There are essentially three independent dimensionless parameters that affect the flow rate of crude oil;

Residual Saturation

- The ratio of gravity to applied pressure forces;

$$\frac{Lg\Delta\rho\cos\theta}{\Delta P}$$

- L = Distance between injection and production wells
- g = Acceleration constant due to gravity
- $\Delta\rho$ = Density difference between crude and displacement fluid
- θ = Formation dip
- ΔP = Pressure drop between injectors and producers

Residual Saturation

- The ratio of capillary pressure forces to applied pressure forces;

$$\frac{\sigma \cos \theta_c}{\sqrt{k}\Delta P}$$

- σ = Interfacial tension between crude and water
- θ_c = Wetting contact angle
- k = Permeability of the reservoir
- ΔP = Pressure drop between injectors and producers

Residual Saturation

- The ratio of the applied pressure forces to viscous forces;

$$\frac{k\Delta P}{\mu L u}$$

- k = Permeability of the reservoir
- ΔP = Pressure drop between injectors and producers
- μ = Crude oil viscosity
- L = Distance between injection and production wells
- u = Volumetric flow velocity (Darcy velocity or volumetric flux)

Residual Saturation

- The residual oil saturation is also dependent on the type of EOR technique which is applied for the recovery of crude. To estimate how much EOR methods can add to oil reserves, the recovery potential of the reservoir has to be known.

- This is defined by the reservoir characteristics and prior recovery mechanism. The oil reservoirs are classified by several models according to the average of the ultimate oil recovery expressed as a percentage of OOIP possibly attained by the respective recovery mechanisms as follows;
    - 5-10% of oil in place is recovered in tight oil reservoirs or heavy oil reservoirs
    - 10-15% of oil in place is recovered in the drive mode of dissolved gas;
    - 25-40% oil in place is recovered at partially water-pumping mode, gas injection or gravitational mode;
    - 40-55% oil in place is recovered by the waterflooding.

Macroscopic Displacement

- Fluid mobilities
- Areal heterogeneity (k, h, Swc, ϕ, Fault, Boundary conditions)
- Gravity and viscous forces
- Total volume of fluid injected
- Injection/production well pattern

Macroscopic displacement efficiency also known as volumetric sweep efficiency, measures the extent to which displacing fluid is in contact with oil bearing parts of the reservoir. It is influenced by the parameters above. Among them, heterogeneity is the most important parameter that affect sweep efficiency. A reservoir may be formed from different layers having different rock properties. Although porosity and connate water saturation may vary aerially and vertically within a reservoir, the most important rock property variation to influence waterflood performance is permeability. Permeabilities pose particular problems because they usually vary by more than an order of magnitude between different strata.

Mobility Ratio

- The mobility of a fluid is defined as the ratio of the effective permeability of the fluid to the viscosity of the fluid.

$$\lambda_m = \frac{k_m}{\mu_m}$$

m = Fluid (can be oil, water, gas)

λ_m = Mobility of fluid (oil, water, gas)

- Fluid mobility is a strong function of fluid saturation.
- Mobility ratio is defined as the mobility of the displacing fluid to the mobility of the displaced fluid, formulated as follows;

$$MR = \frac{\lambda_{displacing}}{\lambda_{displaced}}$$

Mobility Ratio

- For waterflooding;

$$MR = \frac{\lambda_w}{\lambda_o} = \frac{k_w / \mu_w}{k_o / \mu_o} = \frac{k k_{rw} / \mu_w}{k k_{ro} / \mu_o} = \frac{k_{rw}}{k_{ro}} \frac{\mu_o}{\mu_w}$$

k_{rw} and k_{ro} = Relative permeability to water and oil, respectively

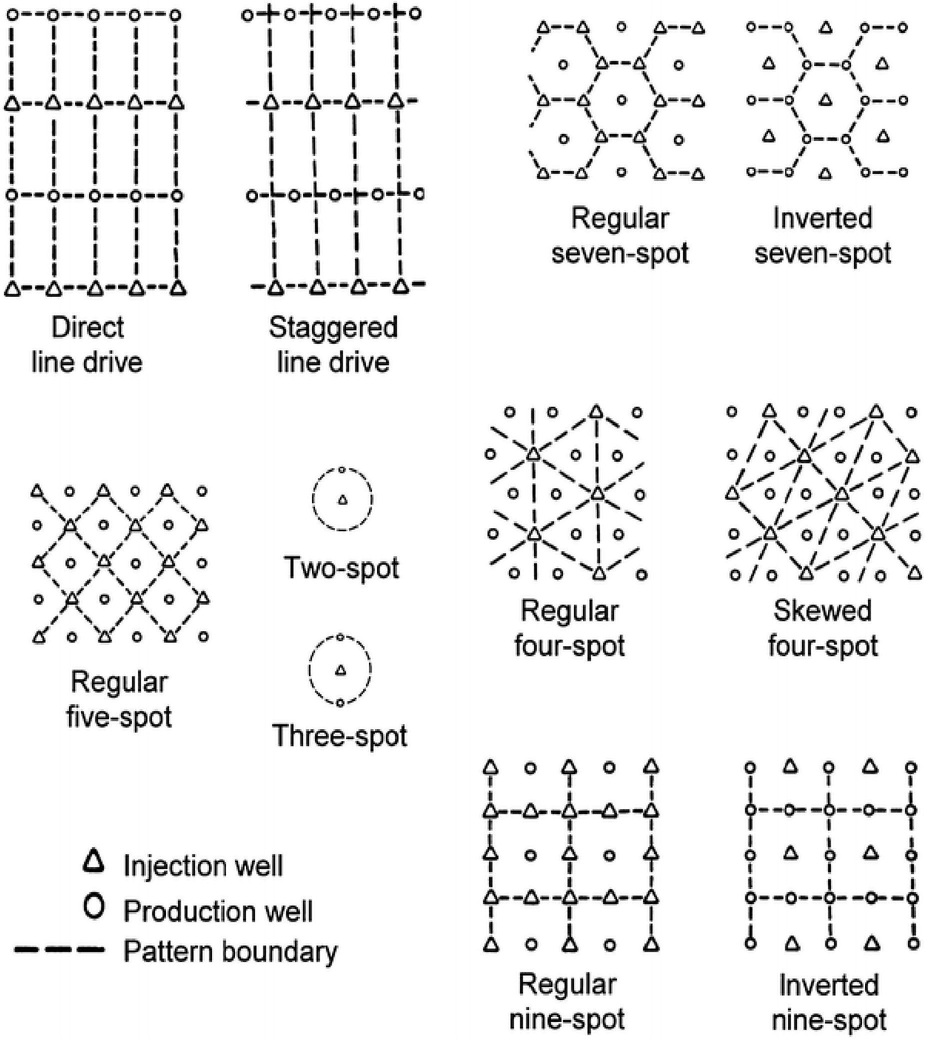
k_w and k_o = Effective permeability to water and oil, respectively

k = Absolute permeability

Mobility Ratio

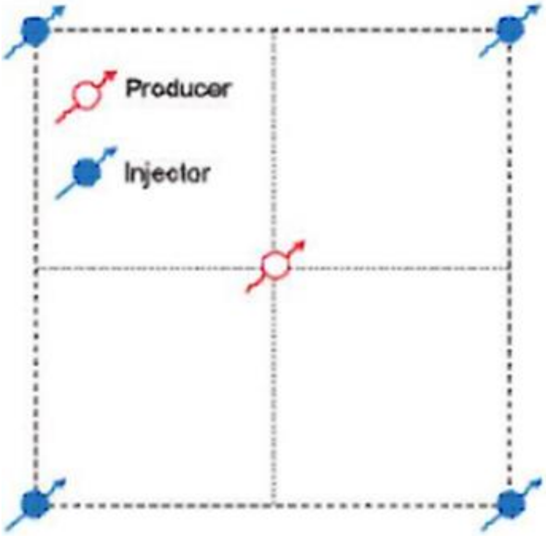
- MR ≤ 1 → Efficient flood, favorable case (Piston-like displacement)
- MR = 1 → Stable displacing
- MR > 1 → Not efficient flood, unfavorable (Viscous fingering)

Well Pattern



Well Pattern

- A regular five-spot pattern consists of a production well surrounded by four injection wells.



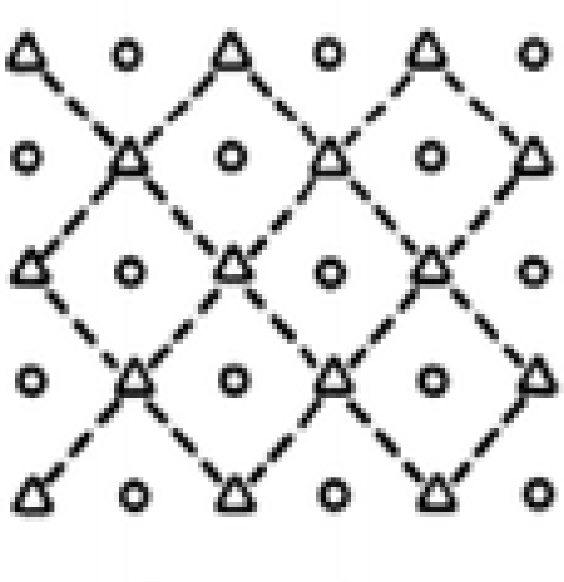
- An inverted 5-spot pattern has an injection well surrounded by four production wells.

Well Pattern

- Displacement performance models based on the ideal 5-spot pattern in which the one production well is surrounded by four injection wells.

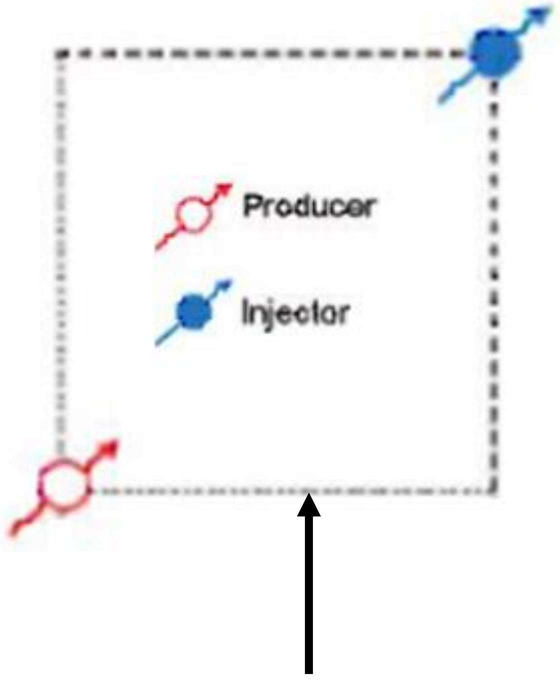
- It is assumed that the injection rates are equal to the production rates.

- Thus, flow is symmetric around each injection well with 0.25 of the injection rate from each well confined to the flow pattern.



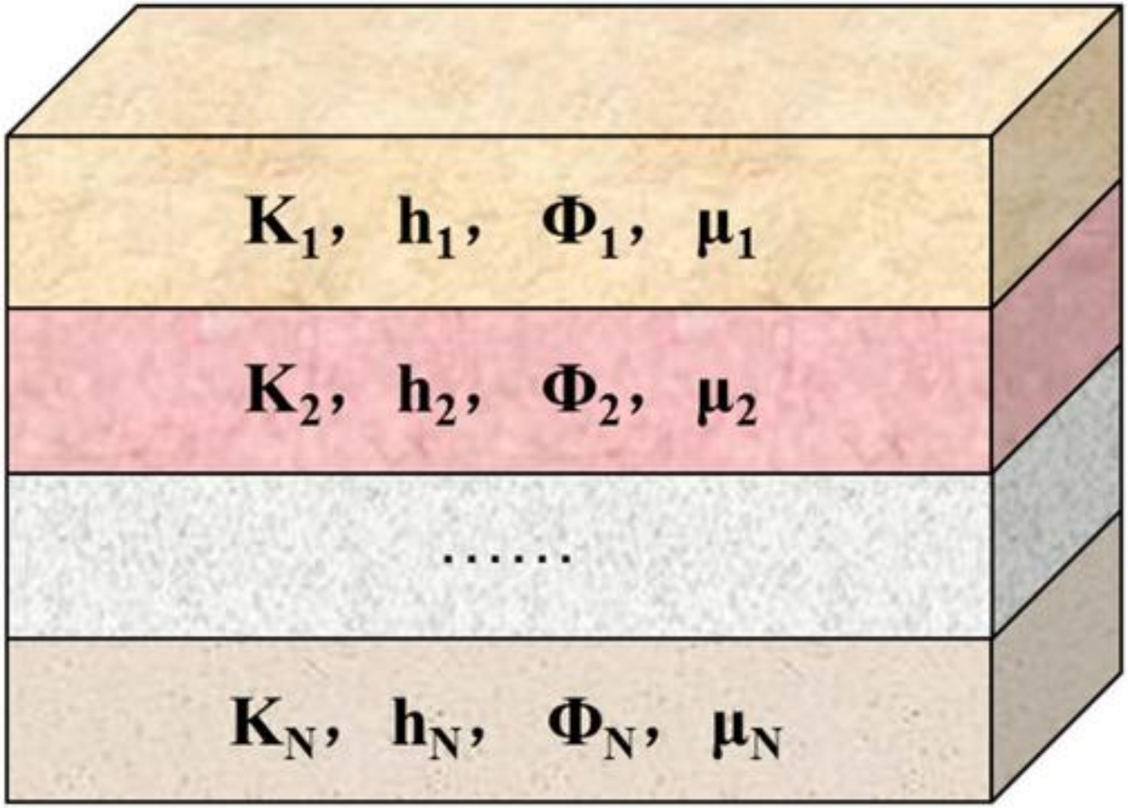
Well Pattern

- The dashed boundaries also represent no-flow boundaries in a homogeneous reservoir where injection and production rates are equal.
- Therefore, analysis of a five-spot pattern in a reservoir can be performed by analyzing the behavior of a single five-spot pattern.
- Each quadrant in a five-spot pattern is symmetric. Therefore, investigators used the quadrant of a five-spot pattern to analyze the displacement performance of the full pattern.



No-flow boundary

Reservoir Heterogeneity



Reservoir Heterogeneity

- Dykstra and Parsons (1950) introduced the concept of the permeability variation V, which is designed to describe the **degree of heterogeneity** within the reservoir.

- Reservoir heterogeneity is measured by the dispersion or scatter of permeability values. A homogeneous reservoir has a permeability variation that approaches zero, while an extremely heterogeneous reservoir has a permeability variation that approaches one.

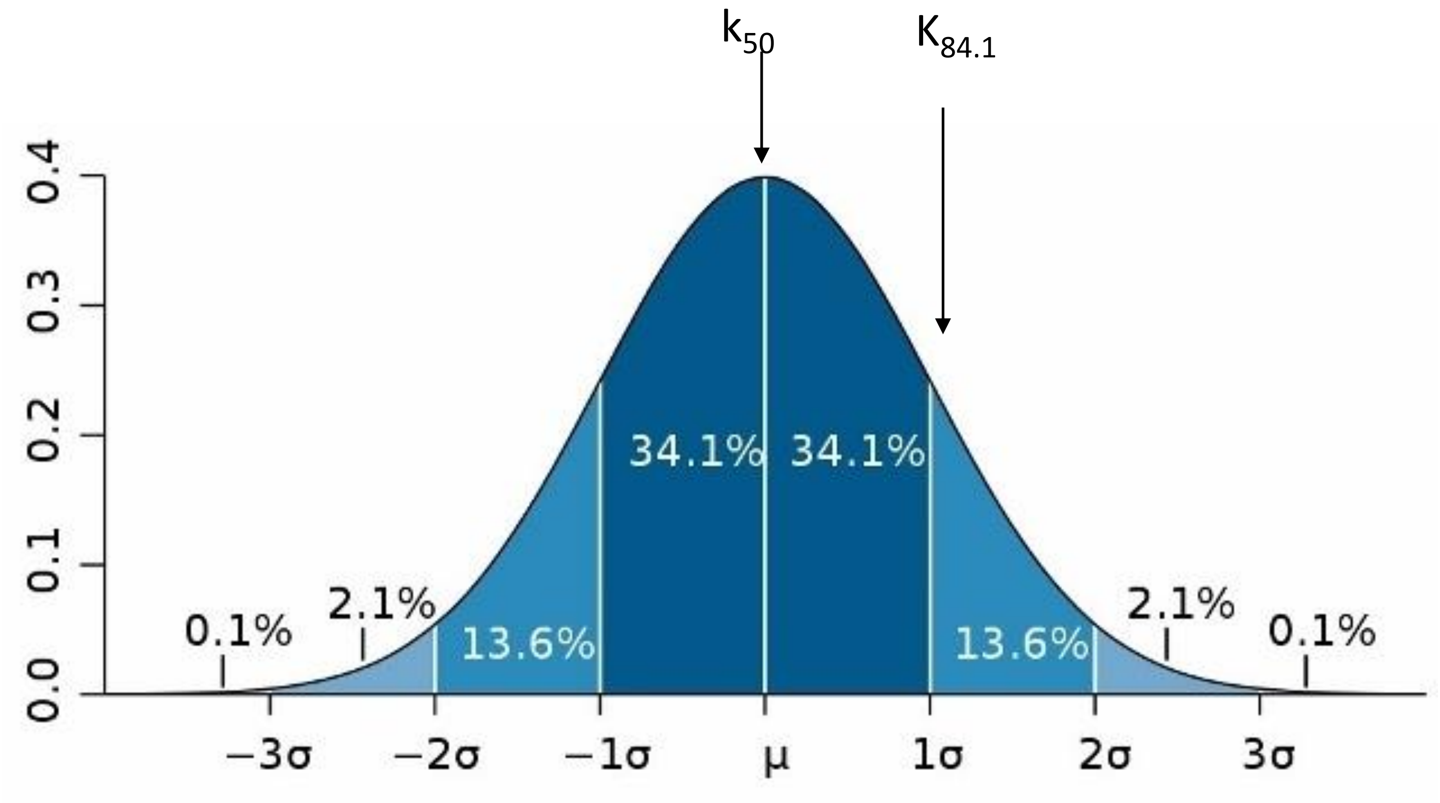
$$V_{\mathrm{k}} = \frac{k_{50} - k_{84.1}}{k_{50}}$$

V_k is the permeability variation

k_{50} is the permeability value at the 50th percentile (median k value)

$k_{84.1}$ is the permeability value at the 84.1th percentile (one standart deviation)

Dykstra-Parson Method



Assumptions for Dykstra-Parson Method

- The reservoir consists of isolated layers of equal thickness having uniform permeability with no cross flow between layers.
- Piston-like displacement occrs; only one phase is flowing in any given volume element.
- There is a linear and steady-state flow.
- The fluids are incompressible; there are no transient pressure effects.

Assumptions for Dykstra-Parson Method

- The pressure drop across every layer is the same.
- Fill-up occurs in all layers prior to flood response. The flood life should be increased to allow for the fill-up period.
- Except for absolute permeability, the rock and fluid properties are the same for all layers.

Dykstra-Parson Method

- Increasing values of permeability variation indicate increasing degrees of vertical heterogeneity in a reservoir. Permeability variations often range from about 0.5 to 0.8; lower numbers maybe observed for relatively uniform reservoirs, and higher numbers may be calculated for very nonuniform reservoirs.

- The Dykstra–Parsons coefficient is an excellent tool for characterizing the degree of reservoirs heterogeneity. The term V_K is also called the *Reservoir Heterogeneity Index*.

Dykstra-Parson Method

- The range of this index is $0<V_K<1$:

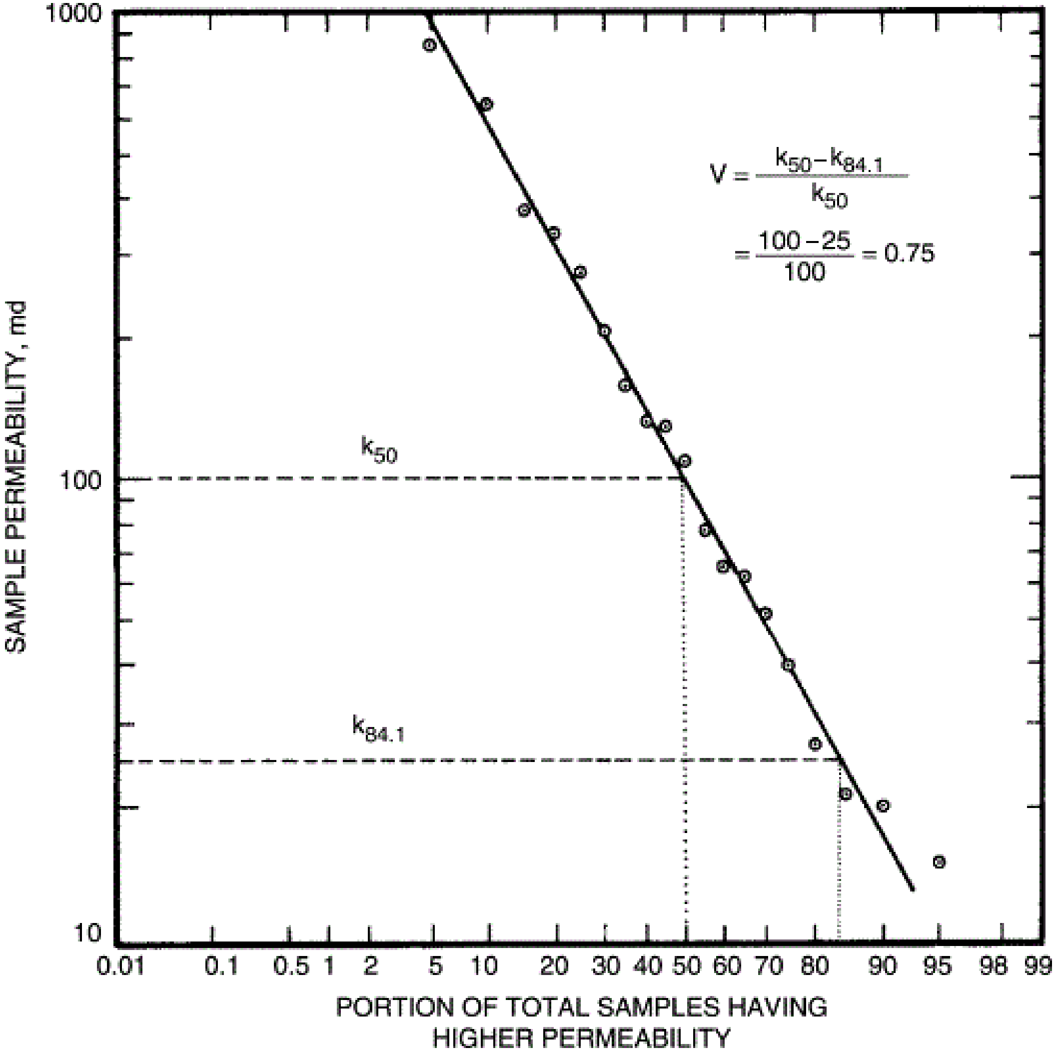
$V_K=0$, ideal homogeneous reservoir
$0<V_K<0.25$, slightly heterogeneous
$0.25<V_K<0.50$, heterogeneous reservoir
$0.50<V_K<0.75$, the reservoir is very heterogeneous
$0.75<V_K<1$, the reservoir is extremely heterogeneous
$V_K=1$, perfectly heterogeneous reservoir

Dykstra-Parson Method Example

Layer	Permeability, md
1	280
2	210
3	860
4	640
5	950
6	21
7	27
8	54
9	40
10	15
11	380
12	340
13	160
14	20
15	63
16	78
17	65
18	135
19	110
20	130

Permeability, md	Percent of Samples with Greater than Stated Permeability
950	0
860	5
640	10
380	15
340	20
280	25
210	30
160	35
135	40
130	45
110	50
78	55
65	60
63	65
54	70
40	75
27	80
21	85
20	90
15	95

Dykstra-Parson Method



$$V = \frac{k_{50} - k_{84.1}}{k_{50}}$$

$$= \frac{100 - 25}{100} = 0.75$$

Enhanced Oil Recovery

References:

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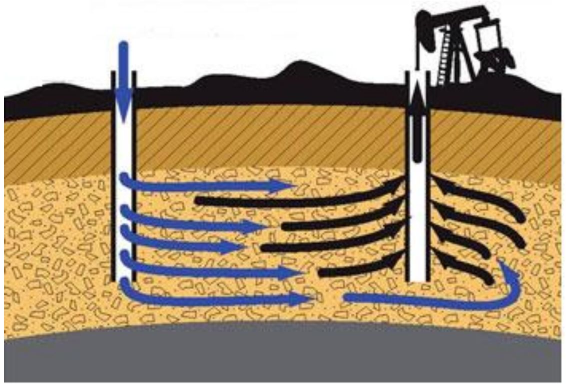
- William C. Lyons, Working Guide to Reservoir Engineering, 2010

PNGE 443
Enhanced Oil Recovery

Chapter 4
Waterflooding



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Waterflooding

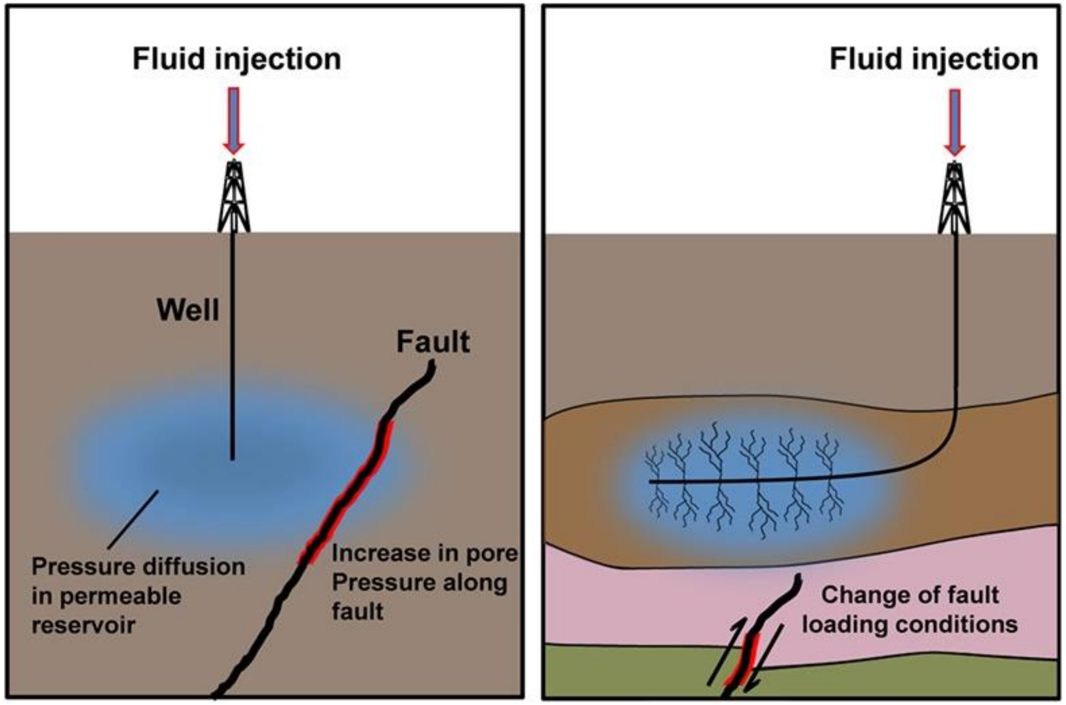
- Waterflooding is the most common secondary oil recovery method.
- In order to increase the performance from waterflooding process, the reservoir rock and fluid properties, reservoir geometry, reservoir depth and fluid saturations should be considered all together.
- It has technical (pressure maintainance) and environmental advantages (management of useless high salinity water)
- It provides pressure support and displaces crude oil towards production wells

Waterflooding

- The important parameters to determine the optimum time for the start of secondary recovery processes was listed by Cole (1969) as follows;
  - Reservoir oil viscosity: Water injection process should be started when the reservoir pressure reaches the bubble point pressure since at that pressure the oil viscosity gets its minimum value. As the oil viscosity gets smaller, mobility ratio will increase which in turns improve the sweep efficiency.
  - Free gas saturation: In water injection process, initial gas saturation should be as much as 10%. This will occur when reservoir pressure is below the bubble point pressure. In gas injection process, zero gas saturation is required. This will occur when the reservoir pressure is at/above the bubble point pressure.
  - Injection equipment cost: The injection equipment cost increases with increasing reservoir pressure. Therefore, lower reservoir pressures are desired for the start of the injection process.
  - Productivity of producing wells: Higher reservoir pressure is desirable to increase the productivity of producing wells. This increase the flowing period of wells, decrease lifting cost.
  - Overall life of reservoir: The injection process should be started as early as possible because operating expenses are an important part of total cost.

Waterflooding

- Waterflooding operations close to faults may trigger earthquakes because of the injection large amount of waters at long durations.



Waterflooding

- **Mobility Ratio**
- After the second phase (water or gas injection) there is still considerable amount of oil remaining, since it was not swept completely from the reservoir. One of the reasons for that phenomenon is the unfavorable mobility ratio. Mobility ratio is defined as the ratio of mobility (λ) of the displacing fluid (water) to the mobility of the displaced fluid (oil), where mobility is permeability (κ) divided by viscosity (μ):

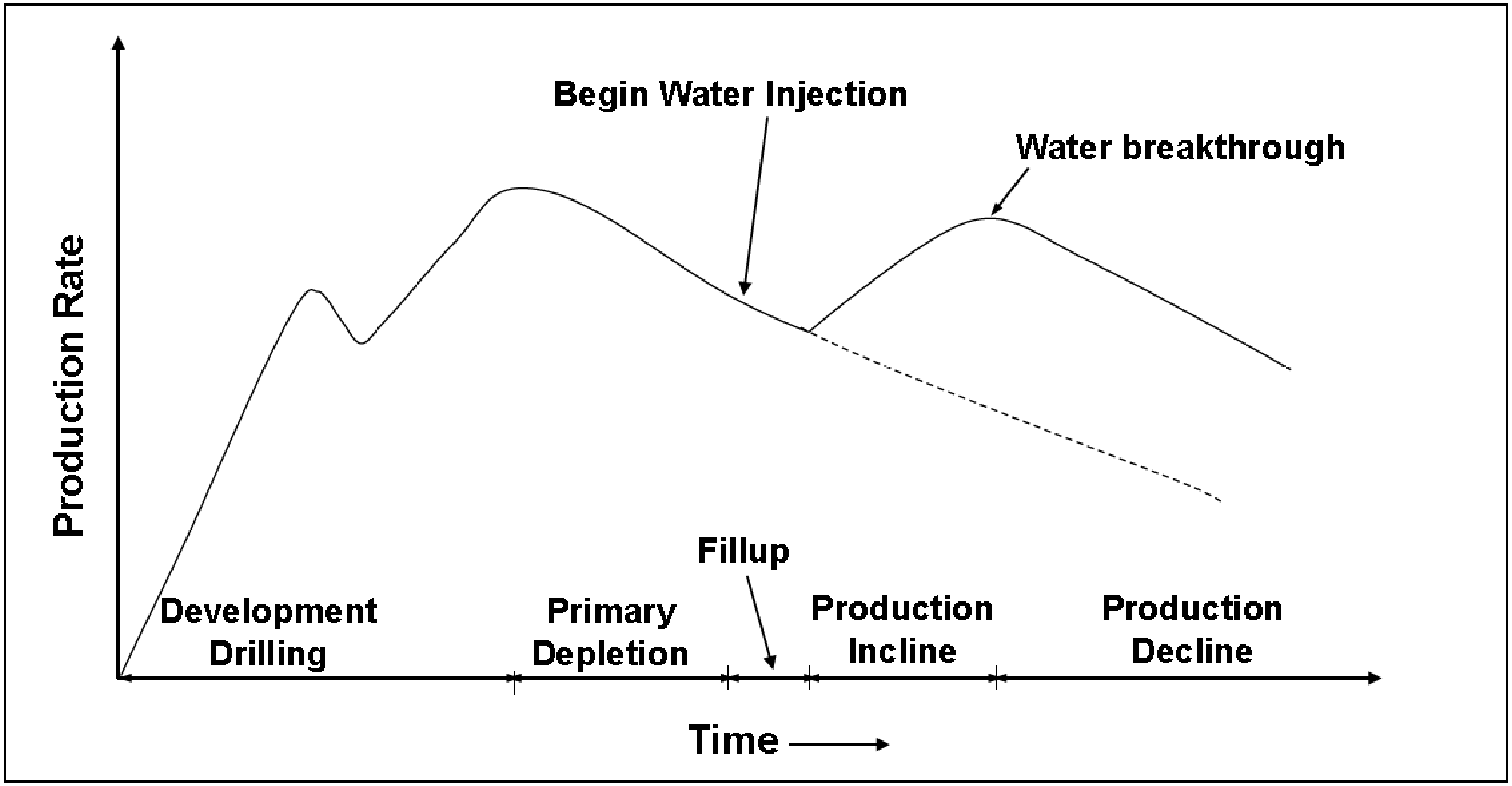
Waterflooding

- Thus, there is an inverse relation between the volumetric sweep efficiency and the mobility ratio. The value of M greater than unity is unfavorable, since this will cause the instability of the displacement process and so called "viscous fingering" effect. Under the condition of a large viscosity difference between the displacing (water, lower viscosity) and displaced (oil, higher viscosity) fluid, the mobility ratio will become larger than one and, thus, poor recovery will be reached.

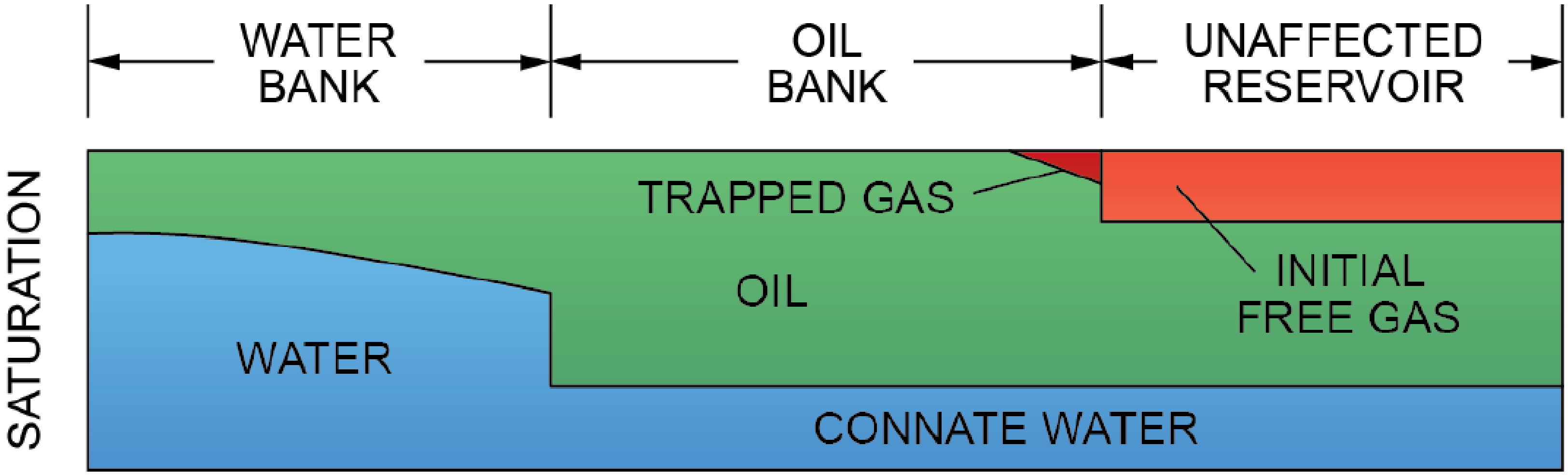
Water Breakthrough

- It is the moment when first water droplet reaches the production well from the injection well.
- Late breakthrough is desirable. Early breakthrough decreases the efficiency.

Waterflooding



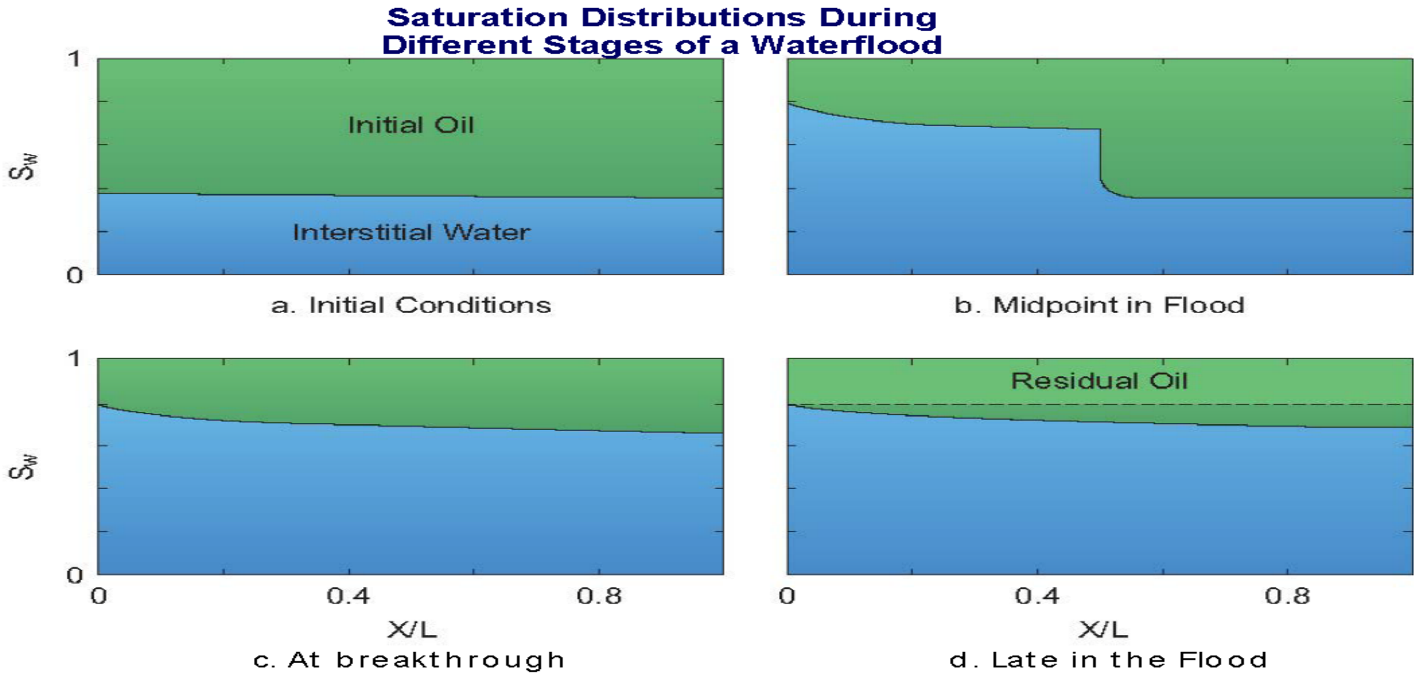
Waterflooding



Saturation Profile During a Waterflood

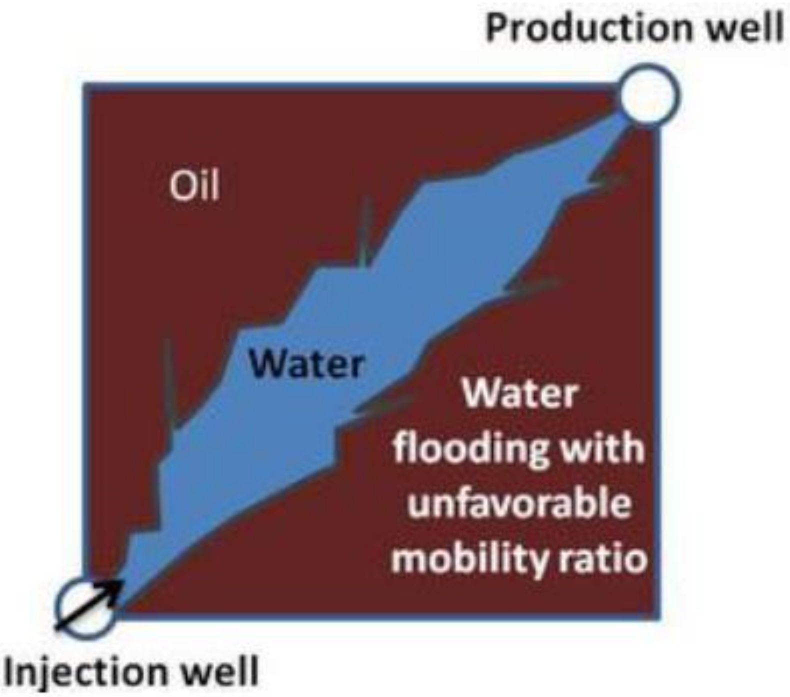
Waterflooding

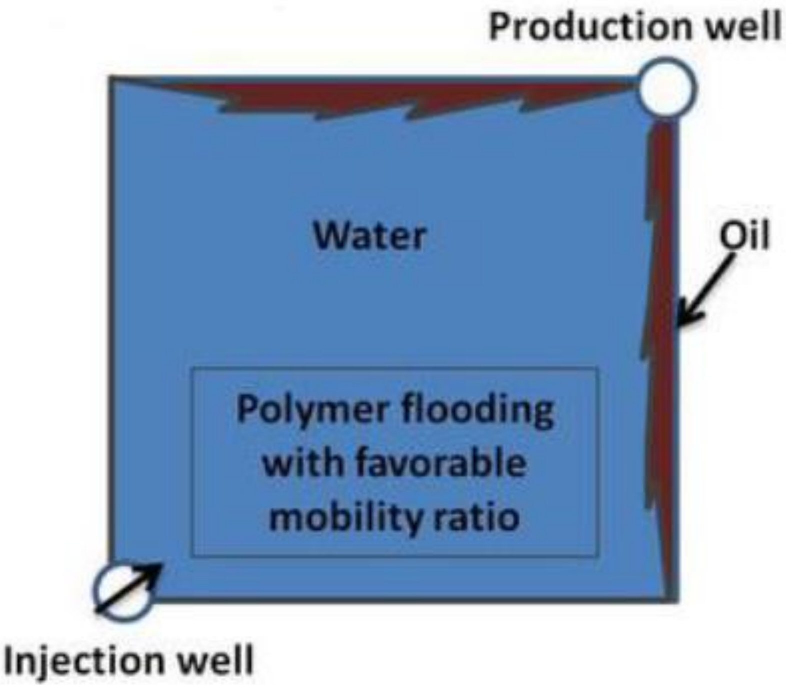
- The displacement of one fluid by another fluid is an unsteady-state process because the saturations of the fluids change with time. This causes changes in relative permeabilities and either pressure or phase velocities.
- Four representative stages of a linear waterflood at connate water saturation;



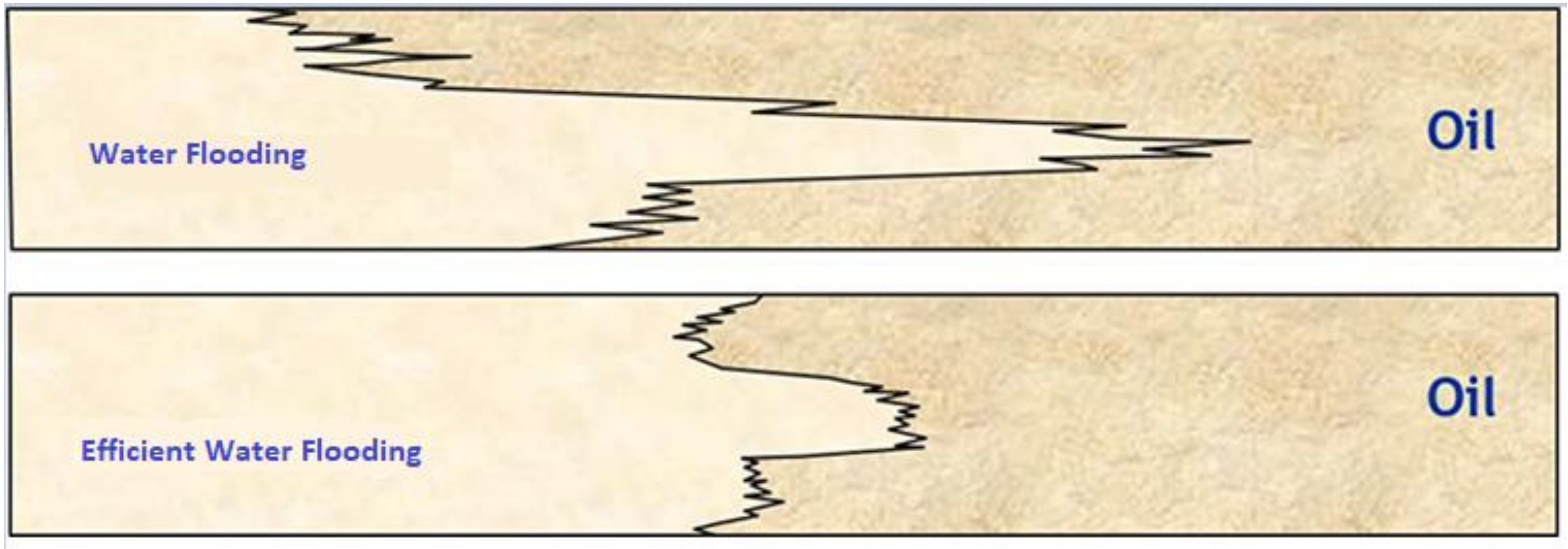
Waterflooding

$$M = \frac{\lambda_{water}}{\lambda_{oil}} = \frac{\kappa_{water} / \mu_{water}}{\kappa_{oil} / \mu_{oil}}$$





Waterflooding



Displacement in Linear Systems

- There are basically two methods to predict the displacement performance by an immiscible fluid;

    - The Buckley-Leverett or Frontal advance method which can be solved easily with graphical techniques
    - The generalized treatment of two phase flow leading to set a partial differential equations that can be solved on a computer with numerical techniques.
    - The application of frontal advance theory to predict the performance of waterflooding in linear systems is going to be covered in this chapter.

Displacement Efficiency

- Displacement efficiency, E_D, is the fraction of movable oil that has been recovered from the swept zone at any given time.

$$E_D = \frac{\text{Volume of oil at the start of flood-Remaining oil volume}}{\text{Volume of oil at the start of flood}} \qquad (1)$$

or

$$E_D = \frac{\dfrac{S_{oi}}{B_{oi}} - \dfrac{\overline{S}_o}{B_o}}{\dfrac{S_{oi}}{B_{oi}}} \qquad (2)$$

with constant formation volume factor, Eq. (2) turns into;

Displacement Efficiency

$$E_D = \frac{S_{oi} - \bar{S}_o}{S_{oi}} \qquad (3)$$

Initial oil saturation, S_{oi}, is given by;

$$S_{oi} = 1 - S_{wi} \qquad (4)$$

The average oil saturation at a particular point during the flood;

$$\bar{S}_o = 1 - \bar{S}_w \qquad (5)$$

If we insert the Eqs. (4) and (5) into Eq. (3);

$$E_D = \frac{\bar{S}_w - S_{wi}}{1 - S_{wi}} \qquad (6)$$

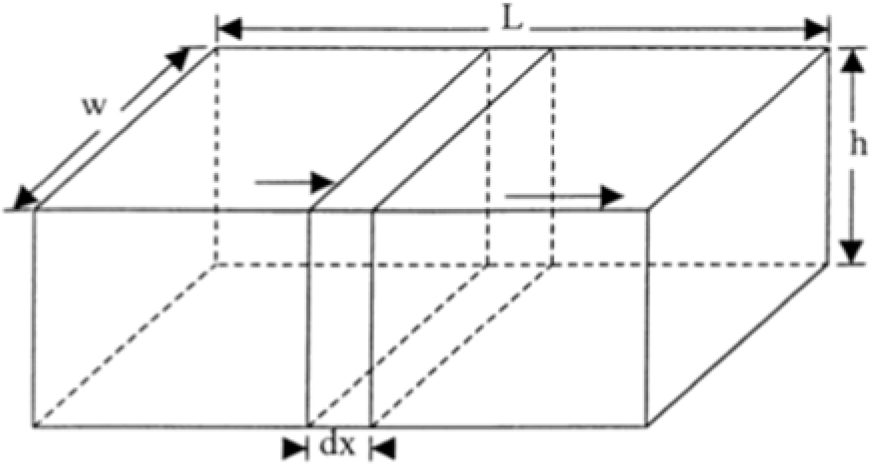
E_D continuously increase with increase in water saturation. The objective is to determine the average water saturation increase in the swept area as a function of cumulative water injected. To determine such a relationship Buckley-Leverett developed frontal displacement theory.

Buckley-Leverett One Dimensional Displacement

- The assumptions for the frontal displacement theory in one dimensional linear system are given below;
    - The rock is considered homogeneous with porosity, ϕ, permeability, k, length, L, and cross-sectional area A.
    - Water is displacing oil and they are immiscible and incompressible.
    - Steady-state flow.
    - There is no gas saturation.
    - Linear one-dimensional flow.
    - Piston like displacement.
    - No mass transfer between phases.

Buckley-Leverett One Dimensional Displacement

- The Buckley-Leverett model was developed by application of the law of conservation of mass to the flow of two fluids (oil and water) in one direction *x*. When oil is displaced by water from a linear system, a linear volume element can be used for derivation.
- Consider a small element of a porous medium shown in figure that has dimensions *Δx*.



Buckley-Leverett One Dimensional Displacement

- Darcy flow is assumed.
- The law of conservation of mass, written in terms of rates is described as follows;

{Mass in} – {Mass out} = {Mas accumulation}

$$\left(\rho_w u_{w_x}\right)_x A\Delta t-\left(\rho_w u_{w_x}\right)_{x+\Delta x} A\Delta t=\rho_w\left(\phi A\Delta x\right)S_w\Big|_{t+\Delta t}-\rho_w\left(\phi A\Delta x\right)S_w\Big|_t \qquad (7)$$

where $\phi A\Delta x$ is the pore volume.

- Rearrange equation;

$$-\left[\left(\rho_w u_{w_x}\right)_{x+\Delta x} A\Delta t-\left(\rho_w u_{w_x}\right)_x A\Delta t\right]=A\Delta x\left(\rho_w S_w\phi\right)_{t+\Delta t}-A\Delta x\left(\rho_w S_w\phi\right)_t \qquad (8)$$

- The definition of a derivative from differential calculus;

$$\frac{\partial A}{\partial x}=\lim_{\Delta x\to 0}\frac{A\left(x+\Delta x\right)-A\left(x\right)}{\Delta x} \qquad (9)$$

Buckley-Leverett One Dimensional Displacement

- Dividing both sides of Eq. (8) by $A\Delta t\Delta x$, we obtain;

$$-\frac{\left(\rho_w u_{w_x}\right)_{x+\Delta x}-\left(\rho_w u_{w_x}\right)_x}{\Delta x}=\frac{\left(\rho_w S_w \phi\right)_{t+\Delta t}-\left(\rho_w S_w \phi\right)_t}{\Delta t} \tag{10}$$

- The limit of Eq. (10) as Δx and Δt approach zero is;

$$-\frac{\partial\left(\rho_w u_{w_x}\right)}{\partial x}=\frac{\partial\left(\rho_w S_w \phi\right)}{\partial t} \tag{11}$$

- Similarly, for oil phase;

$$-\frac{\partial\left(\rho_o u_{o_x}\right)}{\partial x}=\frac{\partial\left(\rho_o S_o \phi\right)}{\partial t} \tag{12}$$

Buckley-Leverett One Dimensional Displacement

- These equations assume that there is no dissolution of oil in water phase (no mass transfer between phases). Eqs. (11) and (12) may also be written in terms of volumetric flow rates q_o and q_w by multiplying both sides of the equations with the cross-sectional area open to flow, A.
- Multiply Eq. (11) with A, obtain;

$$-\frac{\partial\left(\rho_w q_w\right)}{\partial x}=A\frac{\partial\left(\rho_w S_w \phi\right)}{\partial t} \tag{13}$$

- Multiply Eq. (12) with A, obtain;

$$-\frac{\partial\left(\rho_o q_o\right)}{\partial x}=A\frac{\partial\left(\rho_o S_o \phi\right)}{\partial t} \tag{14}$$

Buckley-Leverett One Dimensional Displacement

- In Buckley-Leverett model, water and oil are considered incompressible and thus ρ_o and ρ_w are constant. Porosity is also assumed to be constant.

$$-\frac{\partial q_w}{\partial x} = A\phi \frac{\partial S_w}{\partial t} \tag{15}$$

and

$$-\frac{\partial q_o}{\partial x} = A\phi \frac{\partial S_o}{\partial t} \tag{16}$$

The sum of Eq. (15) and (16);

$$-\frac{\partial \left(q_o + q_w\right)}{\partial x} = A\phi \frac{\partial \left(S_o + S_w\right)}{\partial t} \tag{17}$$

Buckley-Leverett One Dimensional Displacement

- Because $S_o + S_w = 1$;

$$\frac{\partial(q_o + q_w)}{\partial x} = 0 \qquad (18)$$

or $q_o + q_w = q_t = Constant$

- Saturations S_o and S_w vary with distance *x*. However, because oil and water are assumed to be incompressible, the total volumetric flow rate at any time *t* is constant for every position *x* in the linear system.
- The fractional flow of a phase, *f*, is defined as the volume fraction of the phase that is flowing at *x*, *t*.

Buckley-Leverett One Dimensional Displacement

- For oil phase;

$$f_o = \frac{q_o}{q_t} = \frac{q_o}{q_o + q_w} \tag{19}$$

- For water phase;

$$f_w = \frac{q_w}{q_t} = \frac{q_w}{q_o + q_w} \tag{20}$$

- Because the fractional flow is volume balance;

$$f_o + f_w = 1 \tag{21}$$

- Substituting $q_w = f_w q_t$ into Eq. (15);

$$-\frac{\partial f_w}{\partial x} = \frac{A\phi}{q_t}\frac{\partial S_w}{\partial t} \tag{22}$$

Buckley-Leverett One Dimensional Displacement

- To develop a solution for Eq. (22), it is necessary to obtain an equivalent form of equation which involves one dependent variable (either f_w or S_w). In the Buckley-Leverett model, an expression for $\frac{\partial S_w}{\partial t}$ is obtained following the chain rule of differentiation.
- The water saturation in the porous rock is a function of two independent variables *x* and *t* (i.e. $S_w = S_w(x, t)$).

$$dS_w = \left(\frac{\partial S_w}{\partial x}\right)_t dx + \left(\frac{\partial S_w}{\partial t}\right)_x dt \tag{23}$$

- Since the intention is to study the movement of a plane of constant water saturation, that is;

$$dS_w = 0$$

Buckley-Leverett One Dimensional Displacement

$$\left(\frac{\partial S_w}{\partial t}\right)_x = -\left(\frac{\partial S_w}{\partial x}\right)_t \left(\frac{dx}{dt}\right)_{S_w} \qquad (24)$$

$$\left(\frac{dx}{dt}\right)_{S_w} = -\frac{\left(\frac{\partial S_w}{\partial t}\right)_x}{\left(\frac{\partial S_w}{\partial x}\right)_t} \qquad (25)$$

$(dx/dt)_{S_w}$ is the velocity of water saturation at any specified value of S_w.

- When the fractional flow of water is assumed to be only a function of water saturation. If $f_w = f_w(S_w)$, apply the chain rule;

$$\left(\frac{\partial f_w}{\partial x}\right)_t = \left(\frac{\partial f_w}{\partial S_w}\right)_t \left(\frac{\partial S_w}{\partial x}\right)_t \qquad (26)$$

Buckley-Leverett One Dimensional Displacement

- Substitute Eqs. (24) and (26) into Eq. (22);

$$-\left(\frac{\partial f_w}{\partial S_w}\right)_t\left(\frac{\partial S_w}{\partial x}\right)_t=-\frac{A\phi}{q_t}\left(\frac{\partial S_w}{\partial x}\right)_t\left(\frac{dx}{dt}\right)_{S_w} \tag{27}$$

or

$$\left(\frac{dx}{dt}\right)_{S_w}=\left(\frac{\partial f_w}{\partial S_w}\right)_t\frac{q_t}{A\phi} \tag{28}$$

which is the Buckley-Leverett equation (also called the frontal advance equation). The velocity of a plane of constant water saturation is directly proportional to the derivative of the fractional flow equation evaluated for that saturation.

Buckley-Leverett One Dimensional Displacement

- From the definition of fractional flow;

$$q_w = f_w q_t \tag{29}$$

and

$$q_o = \left(1 - f_w\right) q_t \tag{30}$$

- Applying Darcy's equation for linear, one dimensional flow for the simultaneous flow of water and oil in a dipping reservoir with an angle of α from the horizontal plane are (in terms of Darcy units);

$$q_o = \left(1 - f_w\right) q_t = -\frac{k_o A}{\mu_o}\left[\frac{\partial p_o}{\partial x} + g\rho_o \sin\left(\alpha\right)\right] \tag{31}$$

$$q_w = f_w q_t = -\frac{k_w A}{\mu_w}\left[\frac{\partial p_w}{\partial x} + g\rho_w \sin\left(\alpha\right)\right] \tag{32}$$

Buckley-Leverett One Dimensional Displacement

- Arranging Eq. (31) and (32) gives;

$$\frac{(1-f_w)q_t\mu_o}{k_oA}=-\frac{\partial p_o}{\partial x}-g\rho_o\sin(\alpha) \tag{33}$$

$$\frac{f_wq_t\mu_w}{k_wA}=-\frac{\partial p_w}{\partial x}-g\rho_w\sin(\alpha) \tag{34}$$

- Subtracting Eq. (33) from Eq. (34) gives;

$$\frac{f_wq_t\mu_w}{k_wA}-\frac{(1-f_w)q_t\mu_o}{k_oA}=\left(\frac{\partial p_o}{\partial x}-\frac{\partial p_w}{\partial x}\right)-g(\rho_w-\rho_o)\sin(\alpha) \tag{35}$$

- From the definition of capillary pressure, P_c;

$$P_c=p_o-p_w \tag{36}$$

Buckley-Leverett One Dimensional Displacement

- Differentiating Eq. (36) with respect to *x* gives;

$$\frac{\partial P_c}{\partial x} = \frac{\partial p_o}{\partial x} - \frac{\partial p_w}{\partial x} \tag{37}$$

- Inserting Eq. (37) into Eq. (35);

$$\frac{f_w q_t \mu_w}{k_w A} - \frac{(1 - f_w) q_t \mu_o}{k_o A} = \frac{\partial P_c}{\partial x} - g \Delta\rho \sin(\alpha) \tag{38}$$

where $\Delta\rho = \rho_o - \rho_w$

- Rearranging Eq. (38) gives (in Darcy units);

$$f_w = \frac{1}{1 + \frac{k_o}{k_w}\frac{\mu_w}{\mu_o}} + \frac{\left(\frac{k_o A}{\mu_o q_t}\right)\left[\frac{\partial P_c}{\partial x} - g\Delta\rho \sin(\alpha)\right]}{1 + \frac{k_o}{k_w}\frac{\mu_w}{\mu_o}} \tag{39}$$

Buckley-Leverett One Dimensional Displacement

- Eq. (39) can be expressed in oil field units;

$$f_w = \frac{1}{1+\frac{k_o}{k_w}\frac{\mu_w}{\mu_o}} + \frac{\left(\frac{0.001127k_oA}{\mu_o q_t}\right)\left[\frac{\partial P_c}{\partial x} - 0.433g\Delta\rho\sin(\alpha)\right]}{1+\frac{k_o}{k_w}\frac{\mu_w}{\mu_o}} \qquad (40)$$

where

k_o = Effective permeability of water, mD
k_w = Effective permeability of oil, mD
μ_w = Water viscosity, cp
μ_o = Oil viscosity, cp
P_c = Capillary pressure, psi
$\Delta\rho$ = Water-oil density difference, g/cm^3
q_t = Total flow rate, bbl/day
A = Cross-sectional area, ft^2
x = Distance, ft
$\sin(\alpha)$ = Dipping angle (positive for updip flow, negative for downdip flow)

Development of Frontal Advance Equation

- Solution of the frontal advance equation for specified boundary conditions forms the basis for prediction of immiscible displacement in a linear system. Eq. (28) states that a particular water saturation propagates through a porous rock at a constant velocity. This velocity, $(dx/dt)_{S_w}$, is determined uniquely by the water saturation through the fractional flow equation.
- Consider a porous rock that is saturated initially with oil and water and water is at connate water saturation, S_{wc}. At $t=0+$, water is injected into the rock at a constant rate q_t. As time progress, a water saturation profile develops in the porous rock that varies from S_{wc}, as long as no water has reached the end of the core, to $1- S_{or}$ at $x=0$.

Development of Frontal Advance Equation

- The location $(x)_{S_w}$ of any saturation, S_w, can be obtained by integrating Eq. (28) with respect to time;

$$\int_0^{x_{S_w}} dx_{S_w} = \frac{q_t}{A\phi} \int_0^t \left(\frac{\partial f_w}{\partial S_w} \right)_t dt \qquad (41)$$

- When $\partial f_w / \partial S_w$ is only function of S_w;

$$(x)_{S_w} = \frac{q_t t}{A\phi} \left(\frac{df_w}{dS_w} \right)_{S_w} \qquad (42)$$

$$(v)_{S_w} = \left(\frac{dx}{dt} \right)_{S_w} = \frac{q_t}{A\phi} \left(\frac{df_w}{dS_w} \right)_{S_w} \qquad (43)$$

$(x)_{S_w}$ = Distance from injection (x=0) for any specified given saturation.

Development of Frontal Advance Equation

- When $\partial P_c / \partial x = 0$, Eq. (39) becomes;

$$f_w = \frac{1}{1 + \frac{k_o}{k_w}\frac{\mu_w}{\mu_o}} - \frac{\frac{k_o A}{\mu_o q_t} g \Delta\rho \sin(\alpha)}{1 + \frac{k_o}{k_w}\frac{\mu_w}{\mu_o}} \qquad (45)$$

- When *x* is in the horizontal plane, *α = 0*, and there is no gravity term, Eq. (39) becomes;

$$f_w = \frac{1}{1 + \frac{k_o}{k_w}\frac{\mu_w}{\mu_o}} \qquad (46)$$

Development of Frontal Advance Equation

- When water is injected into this linear system at a sufficient rate for the frontal-advance assumptions to apply, at the lower range of water saturations between S_{wc} and S_{wf}, all saturations move at the same velocity as a function of time and distance. Notice that all saturations in that range have the same value for the slope and, therefore, the same velocity as given by Eq. (43);

$$(v)_{S_w<S_{wf}} = \left(\frac{dx}{dt}\right)_{S_w<S_{wf}} = \frac{q_t}{A\phi}\left(\frac{df_w}{dS_w}\right)_{S_w<S_{wf}} \tag{47}$$

or for $S_{wc} < S_w \le S_{wf}$;

$$(v)_{S_{wf}} = \left(\frac{dx}{dt}\right)_{S_w=S_{wf}} = \frac{q_t}{A\phi}\left(\frac{\partial f_w}{\partial S_w}\right)_{S_w=S_{wf}} \tag{48}$$

Development of Frontal Advance Equation

- For $S_{wf} \leq S_w \leq 1\text{-}S_{or}$;

$$(v)_{S_w} = \left(\frac{dx}{dt}\right)_{S_w} = \frac{q_t}{A\phi}\left(\frac{\partial f_w}{\partial S_w}\right)_{S_w} \tag{49}$$

- We can also conclude that all saturations in this particular range will travel the same distance *x* at any particular time, as given by Eq. (42);

$$(x)_{S_w<S_{wf}} = \frac{q_t t}{A\phi}\left(\frac{\partial f_w}{\partial S_w}\right)_{S_w<S_{wf}} \tag{50}$$

or for $S_{wc} < S_w \leq S_{wf}$;

$$(x)_{S_{wf}} = \frac{q_t t}{A\phi}\left(\frac{\partial f_w}{\partial S_w}\right)_{S_{wf}} \tag{51}$$

Development of Frontal Advance Equation

- For $S_{wf} \le S_w \le 1\text{-}S_{or}$;

$$(x)_{S_w} = \frac{q_t t}{A\phi}\left(\frac{\partial f_w}{\partial S_w}\right)_{S_w} \tag{52}$$

- The slope of the tangent is given by;

$$\left(\frac{\partial f_w}{\partial S_w}\right)_{S_{wf}} = \frac{f_{wf} - f_{wc}}{S_{wf} - S_{wc}} = \frac{f_{wf}}{S_{wf} - S_{wc}} \tag{53}$$

f_{wc} = Fractional flow of water at connate water saturation = 0

- Time to breakthrough, t_{bt} , is given by;

$$t_{bt} = \frac{A\phi L}{q_t}\frac{1}{\left(\frac{\partial f_w}{\partial S_w}\right)_{S_{wf}}} \tag{54}$$

Development of Frontal Advance Equation

- In terms of field units;

$$(v)_{S_w} = \left(\frac{dx}{dt}\right)_{S_w} = \frac{5.615q_t}{A\phi}\left(\frac{\partial f_w}{\partial S_w}\right)_{S_w} \tag{55}$$

$$(x)_{S_w} = \frac{5.615q_t t}{A\phi}\left(\frac{\partial f_w}{\partial S_w}\right)_{S_w} \tag{56}$$

$$t_{bt} = \frac{A\phi L}{5.615q_t}\frac{1}{\left(\frac{\partial f_w}{\partial S_w}\right)_{S_{wf}}} \tag{57}$$

Development of Frontal Advance Equation

where

v_{S_w}= Velocity of water saturation at any specified value of S_w, ft/day

f_w = Fractional flow of water

ϕ = Porosity

q_t = Total flow rate, bbl/day

A = Area, ft^2

L = Distance between injector and producer, ft

t = Time from the beginning of injection, day

$(x)_{S_w}$ = distance from injection (x=0) for any specified given saturation, ft

Estimating the Displacement Performance

- In order to estimate the displacement performance, the volume of oil displaced at any time, the rate of oil production and the volume of water must be calculated.

Oil displacement:

- Until water breakthrough, oil production rate will be equal to the water injection rate due to the incompressible fluid flow assumption. Moreover, the water initially exist in the system is at connate water saturation (immobile).
- When water breakthrough occurs, a water saturation gradient exists from the inlet to the end of the system.

Estimating the Displacement Performance

- Note that for two-phase flow, the total flow rate, q_t, is essentially equal to the injection rate, i_w, or;

$$q_t = i_w \tag{58}$$

- The cumulative water injection;

$$W_{inj} = i_w t = q_t t \tag{59}$$

- The cumulative water injected at breakthrough;

$$W_{ibt} = i_w t_{bt} = \frac{A\phi L}{5.615} \frac{1}{\left(\frac{df_w}{dS_w}\right)_{S_{wf}}} = V_p \frac{1}{\left(\frac{df_w}{dS_w}\right)_{S_{wf}}} \tag{60}$$

Estimating the Displacement Performance

- The average water saturation in the reservoir at breakthrough, $\overline{S_{wbt}}$, is determined by extrapolating the tangent to fractional flow curve to $f_w = 1$. If there is initial water saturation different from the connate water saturation, the tangent line must be originated from initial water saturation.

$$\left(\frac{\partial f_w}{\partial S_w}\right)_{S_{wf}} = \frac{1-0}{\bar{S}_{wbt} - S_{wc}} = \frac{1}{\bar{S}_{wbt} - S_{wc}} \tag{61}$$

- Eq. (60) can be written also;

$$W_{ibt} = i_w t_{bt} = \frac{A\phi L}{5.615} \frac{1}{\left(\frac{df_w}{dS_w}\right)_{S_{wf}}} = V_p \frac{1}{\left(\frac{df_w}{dS_w}\right)_{S_{wf}}} = V_p \left(\bar{S}_{wbt} - S_{wc}\right) \tag{62}$$

V_P = Pore volume, bbl

Estimating the Displacement Performance

- Conventionally, Q_i refers to the total pore volumes of water injected. From Eq. (60) and using Eq. (53), Q_i at breakthrough is;

$$Q_{ibt} = \frac{W_{ibt}}{V_p} = \frac{1}{\left(\frac{df_w}{dS_w}\right)_{S_{wf}}} = \frac{S_{wf} - S_{wc}}{f_{wf}} = \bar{S}_{wbt} - S_{wc} \tag{63}$$

where

Q_{ibt} = Cumulative pore volumes of water injected at breakthrough

Estimating the Displacement Performance

- The produced well is designated as Well 2 and, therefore, the water saturation and water cut at the producing well are denoted as S_{w2} and f_{w2}, respectively. After breakthrough, the water saturation at the producing well reaches any assumed value S_{w2}, the fractional flow curve can be used to determine;
  - The water cut at which the tangent line drawn to the fractional flow curve is the production well water cut f_{w2}.
  - The saturation at which the tangent intersects $f_w = 1$ is the average water saturation in the swept area, $\overline{S_{w2}}$.
  - Cumulative water injected in pore volumes, i.e., Q_i

$$\overline{S}_{w2} = S_{w2} + \frac{1 - f_{w2}}{\left(\frac{df_w}{dS_w}\right)_{S_{w2}}} \qquad (64)$$

Estimating the Displacement Performance

- Cumulative pore volume of injected at the time when the water saturation reaches S_{w2} at the producing well;

$$Q_i = \frac{1}{\left(\frac{df_w}{dS_w}\right)_{S_{w2}}} \tag{65}$$

$$\overline{S}_{w2} = S_{w2} + \frac{q_t t}{A\phi L}\left(1 - f_{w2}\right) = S_{w2} + Q_i\left(1 - f_{w2}\right) \tag{66}$$

Estimating the Displacement Performance

- The displaced hydrocarbon saturation is;

$$\overline{S}_{w2} - S_{wc} \tag{67}$$

- Cumulative oil displaced, N_p is given by;

$$N_p = V_p\left(\overline{S}_{w2} - S_{wc}\right) \tag{68}$$

- After water arrives at the production well;

$$(x)_{S_{w2}} = L = \frac{5.615 q_t t}{A\phi}\left(\frac{\partial f_w}{\partial S_w}\right)_{S_{w2}} \tag{69}$$

- The tangent line drawn to the fractional flow curve at a saturation S_{w2} is higher than S_{wf}.

Estimating the Displacement Performance

Production Rates:

- The fractional flow of water is determined from the frontal advance solution for every saturation of S_w and can be used t estimate the flow rates;

$$q_w = \frac{f_w q_t}{B_w} \tag{70}$$

$$q_o = \frac{f_o q_t}{B_o} \tag{71}$$

and

$$q_o = \frac{\left(1 - f_w\right) q_t}{B_o} \tag{72}$$

Estimating the Displacement Performance

Water-Oil Ratio (WOR):

- The WOR is a measure of the efficiency of the displacement at appoint in the process. In production operations, it represents the volume of water that must be handled to produce a unit volume of oil. The following defines the WOR for a linear system;

$$WOR = \frac{q_w}{q_o} \quad (73)$$

$$WOR(resbbl) = \frac{f_w}{f_o} \qquad WOR(stb) = \frac{f_w}{f_o}\frac{B_o}{B_w} \quad (74)$$

$$f_w = \frac{q_w}{q_w + q_o} = \frac{\frac{q_w}{q_o}}{\frac{q_w}{q_o} + 1} = \frac{WOR}{WOR + 1} \quad (75)$$

Estimating the Displacement Performance

- Displacement efficiency;

$$E_D = \frac{\text{Displaced hydrocarbon volume}}{\text{Initial hydrocarbon volume}}$$

- Displacement at breakthrough in terms of original oil in place (OOIP);

$$E_D = \frac{\left(\overline{S}_{wbt} - S_{wc}\right) AL\phi}{\left(1 - S_{wc}\right) AL\phi}$$

$$E_D = \frac{\overline{S}_{wbt} - S_{wc}}{1 - S_{wc}}$$

Estimating the Displacement Performance

- Displacement efficiency at breakthrough in terms of recoverable oil place (ROIP);

$$E_D = \frac{\overline{S}_{wbt} - S_{wc}}{1 - S_{wc} - S_{or}}$$

- Displacement efficiency after breakthrough in terms of OOIP;

$$E_D = \frac{\overline{S}_{w2} - S_{wc}}{1 - S_{wc}}$$

- Displacement efficiency after breakthrough in terms of ROIP;

$$E_D = \frac{\overline{S}_{w2} - S_{wc}}{1 - S_{wc} - S_{or}}$$

Estimating the Displacement Performance

- For waterflooding;

$$MR = \frac{\lambda_w}{\lambda_o} = \frac{k_w / \mu_w}{k_o / \mu_o} = \frac{k k_{rw} / \mu_w}{k k_{ro} / \mu_o} = \frac{k_{rw}}{k_{ro}} \frac{\mu_o}{\mu_w}$$

k_{rw} and k_{ro} = Relative permeability to water and oil, respectively

k_w and k_o = Effective permeability to water and oil, respectively

k = Absolute permeability

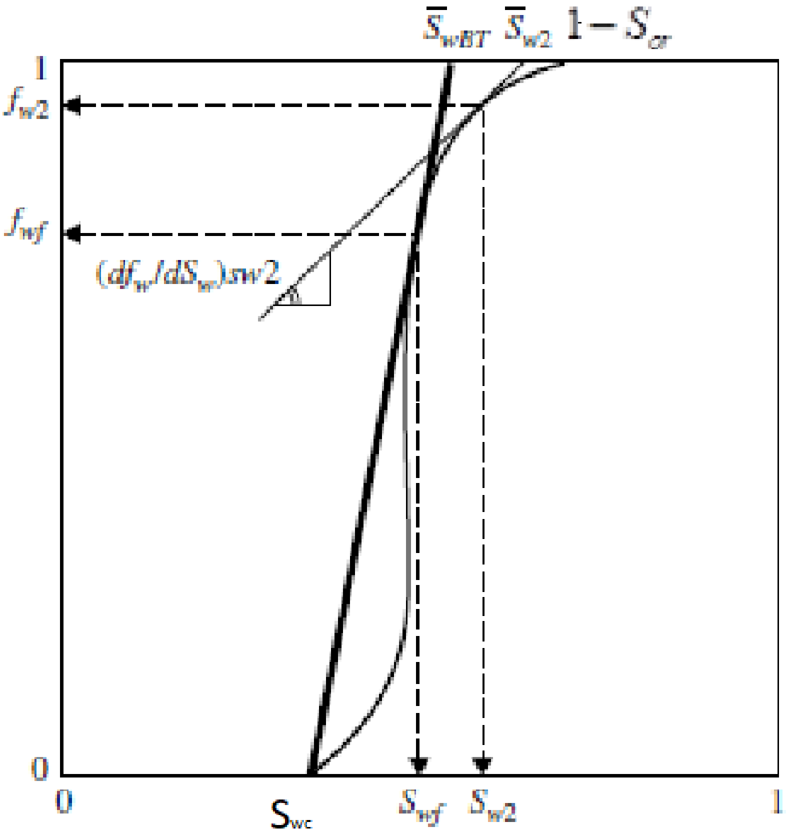
Fractional Flow Curve

- Fractional flow equation is used to calculate the fraction of flow which is water, at any point in the reservoir if the water saturation is known at that point.

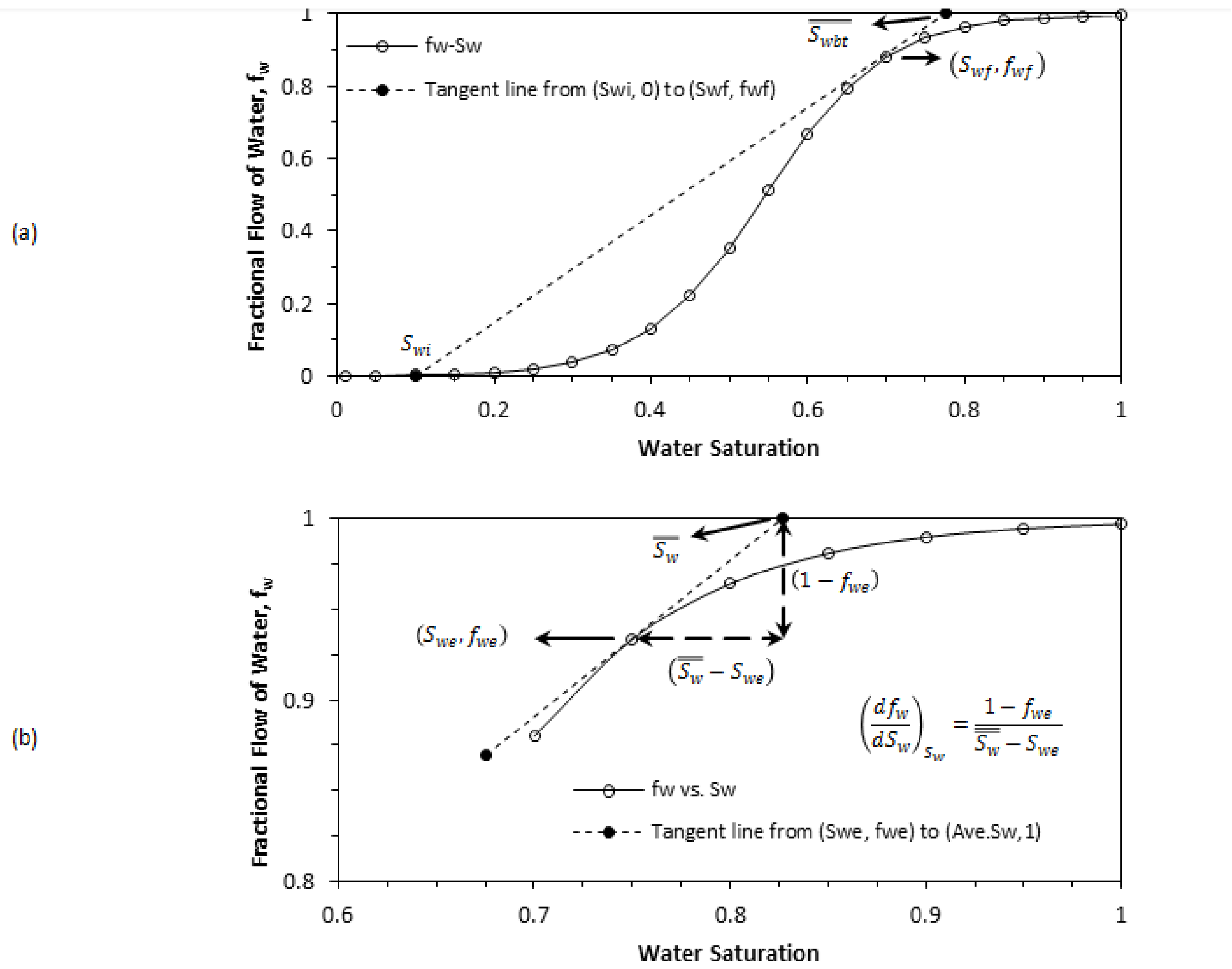
- In a water flooding operation, we want to have small fractional flow of water. Thus, as fractional flow curve shifts to right, better oil recovery results.

Fractional Flow Curve

- The flood-front or breakthrough saturation (S_{wf}) is found by constructing a tangent to the fractional-flow curve from S_{wc}, when the water in the rock is initially at connate saturation (i.e., immobile).
- If there is initial water saturation different from the connate water saturation, the tangent line must be originated from initial water saturation.
- The fractional flow equation is used to calculate the fraction of the total flow which is water, at any point in the reservoir, assuming the water saturation at that point is known.

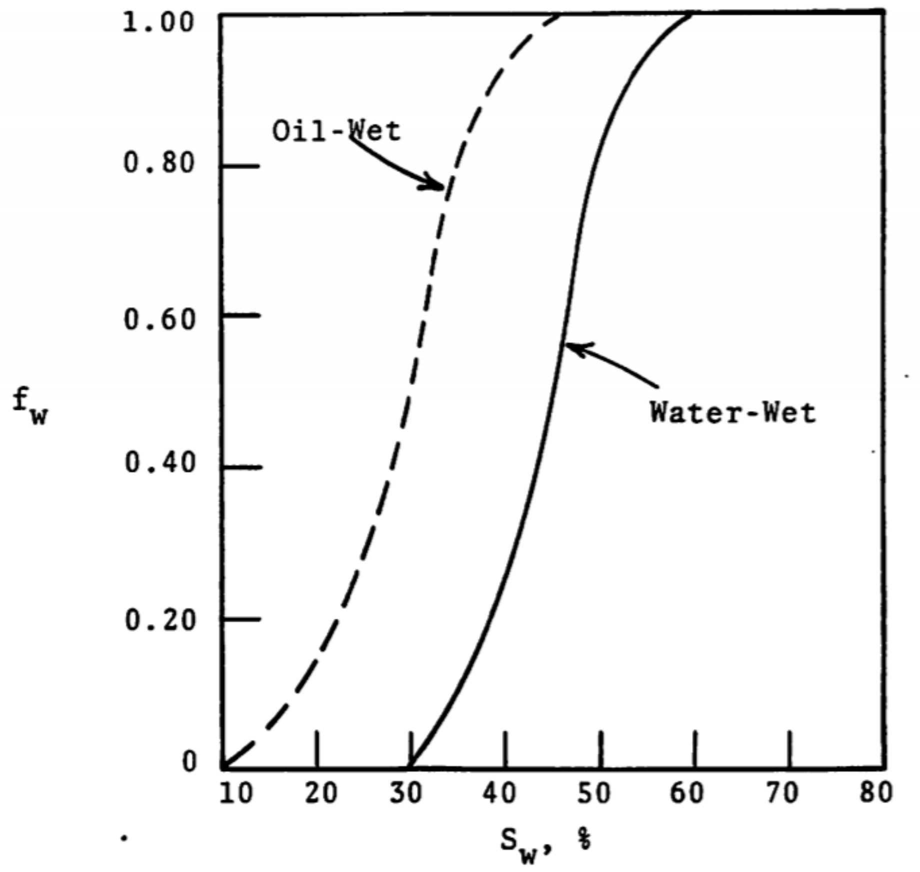


Fractional Flow Curve



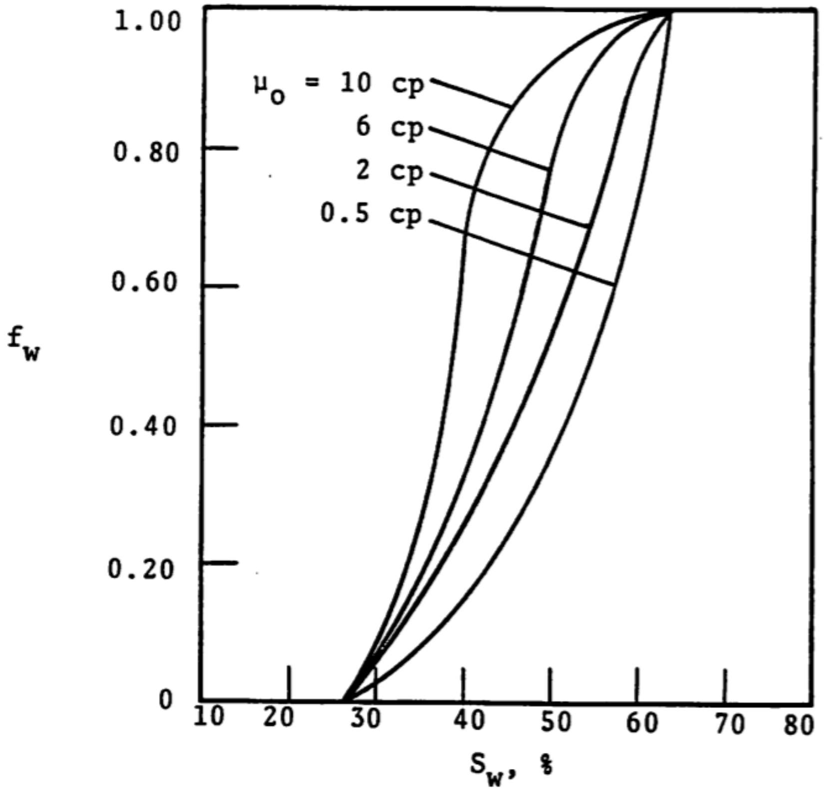
Application of the Welge Graphical Technique to Determine: (a) The Front Saturation, (b) Oil Recovery After Breakthrough

Fractional Flow Curve



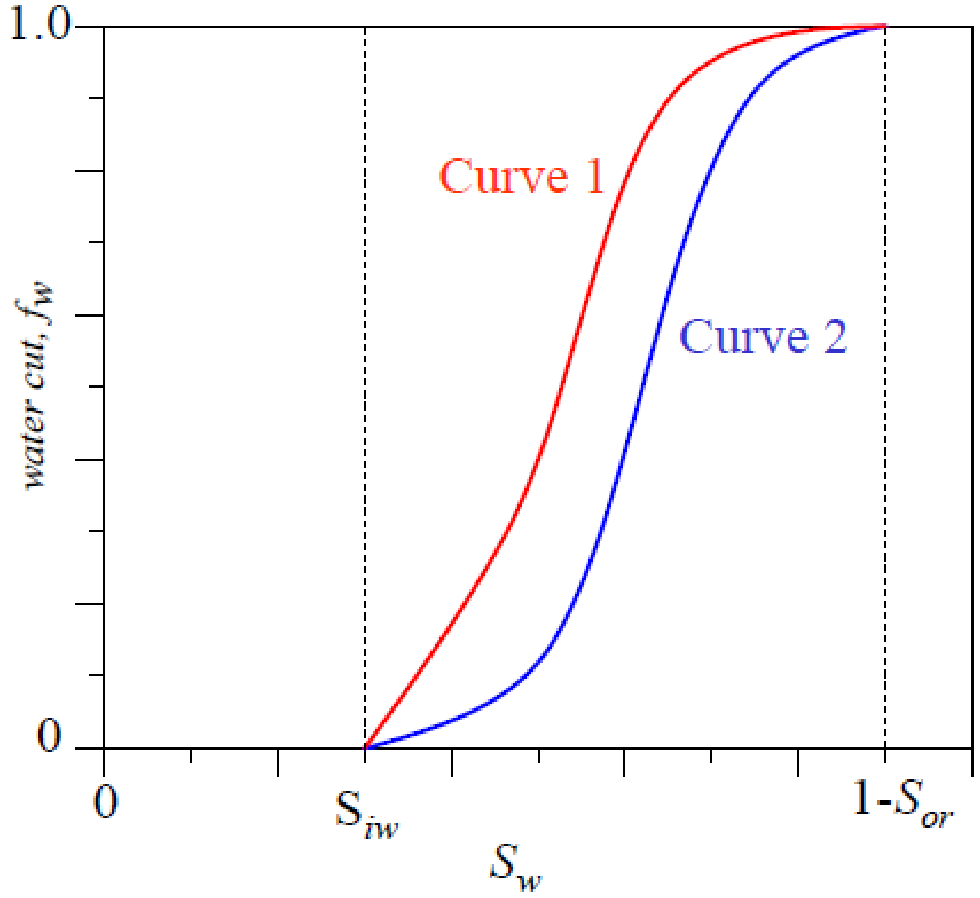
Since it is desirable to minimize f_w at a particular saturation condition, water-wet reservoirs will yield a higher displacement efficiency and higher oil recovery than comparable oil-wet reservoirs.

Fractional Flow Curve



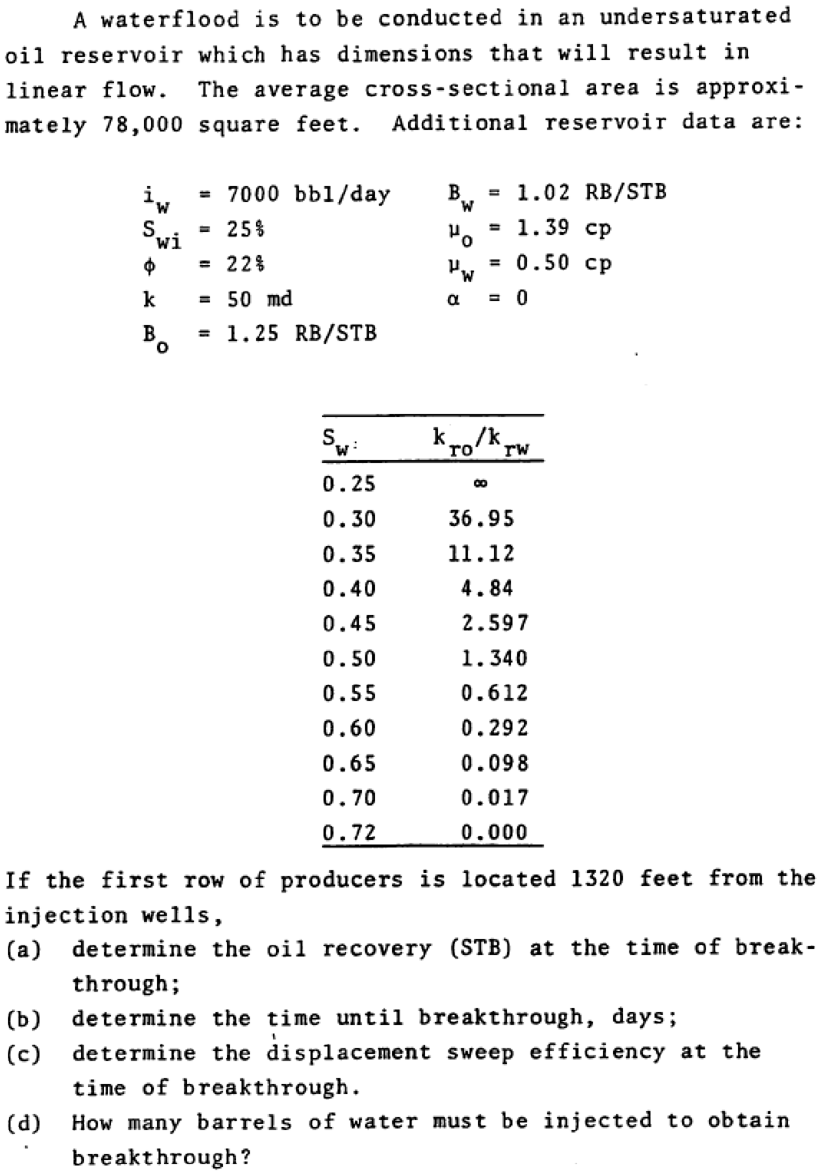
A displacement process can be improved by increasing the water viscosity or by decreasing the oil viscosity. The effect of oil viscosity on the fractional flow curve is depicted for a particular set of reservoir conditions.

Fractional Flow Curve



Curve 2 provides better oil recovery than Curve 1

Waterflooding Class Example



A waterflood is to be conducted in an undersaturated oil reservoir which has dimensions that will result in linear flow. The average cross-sectional area is approximately 78,000 square feet. Additional reservoir data are:

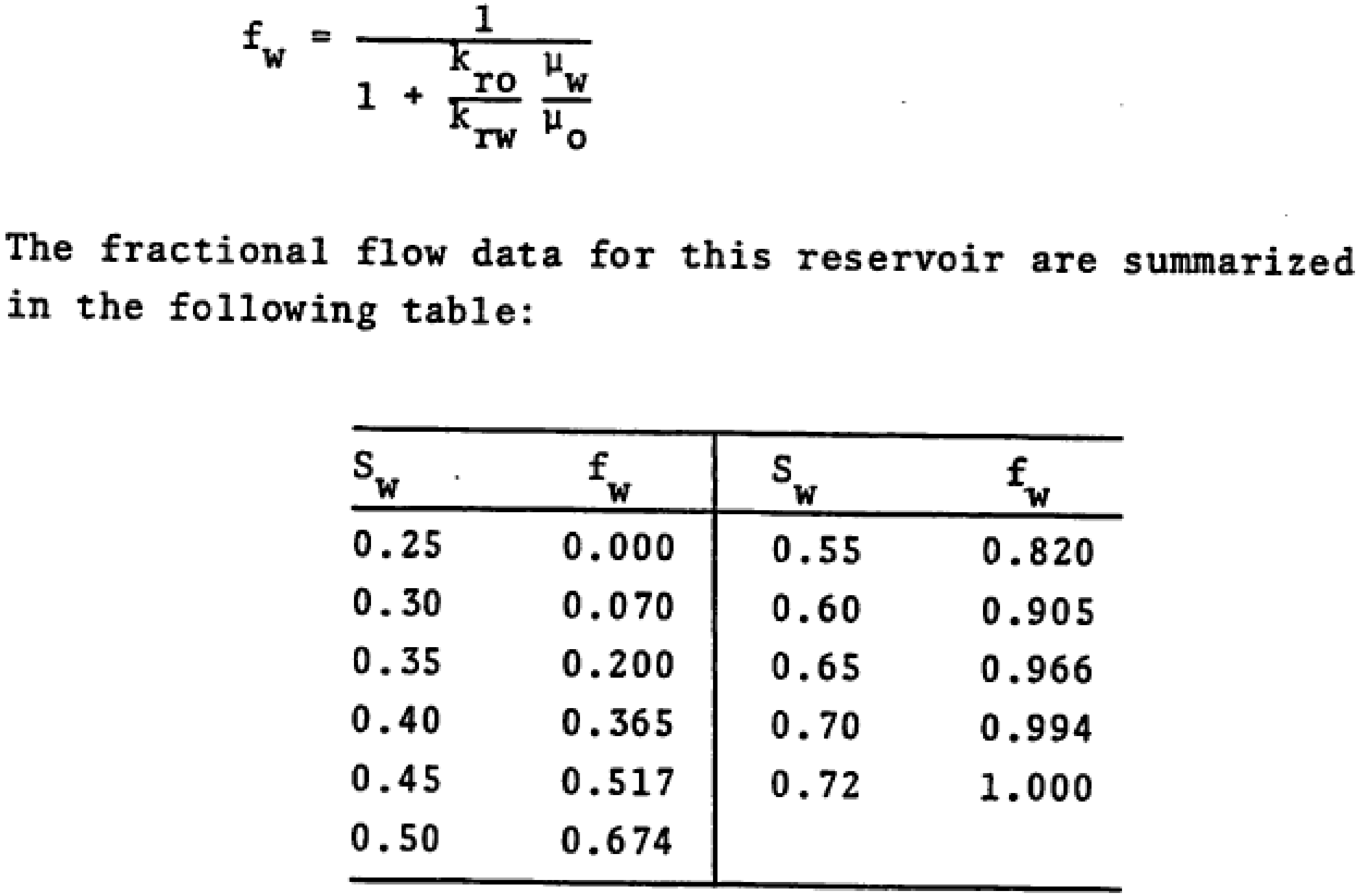
i_w = 7000 bbl/day
S_{wi} = 25%
ϕ = 22%
k = 50 md
B_o = 1.25 RB/STB
B_w = 1.02 RB/STB
μ_o = 1.39 cp
μ_w = 0.50 cp
α = 0

S_w	k_{ro}/k_{rw}
0.25	∞
0.30	36.95
0.35	11.12
0.40	4.84
0.45	2.597
0.50	1.340
0.55	0.612
0.60	0.292
0.65	0.098
0.70	0.017
0.72	0.000

If the first row of producers is located 1320 feet from the injection wells,

(a) determine the oil recovery (STB) at the time of breakthrough;
(b) determine the time until breakthrough, days;
(c) determine the displacement sweep efficiency at the time of breakthrough.
(d) How many barrels of water must be injected to obtain breakthrough?

Waterflooding Class Example

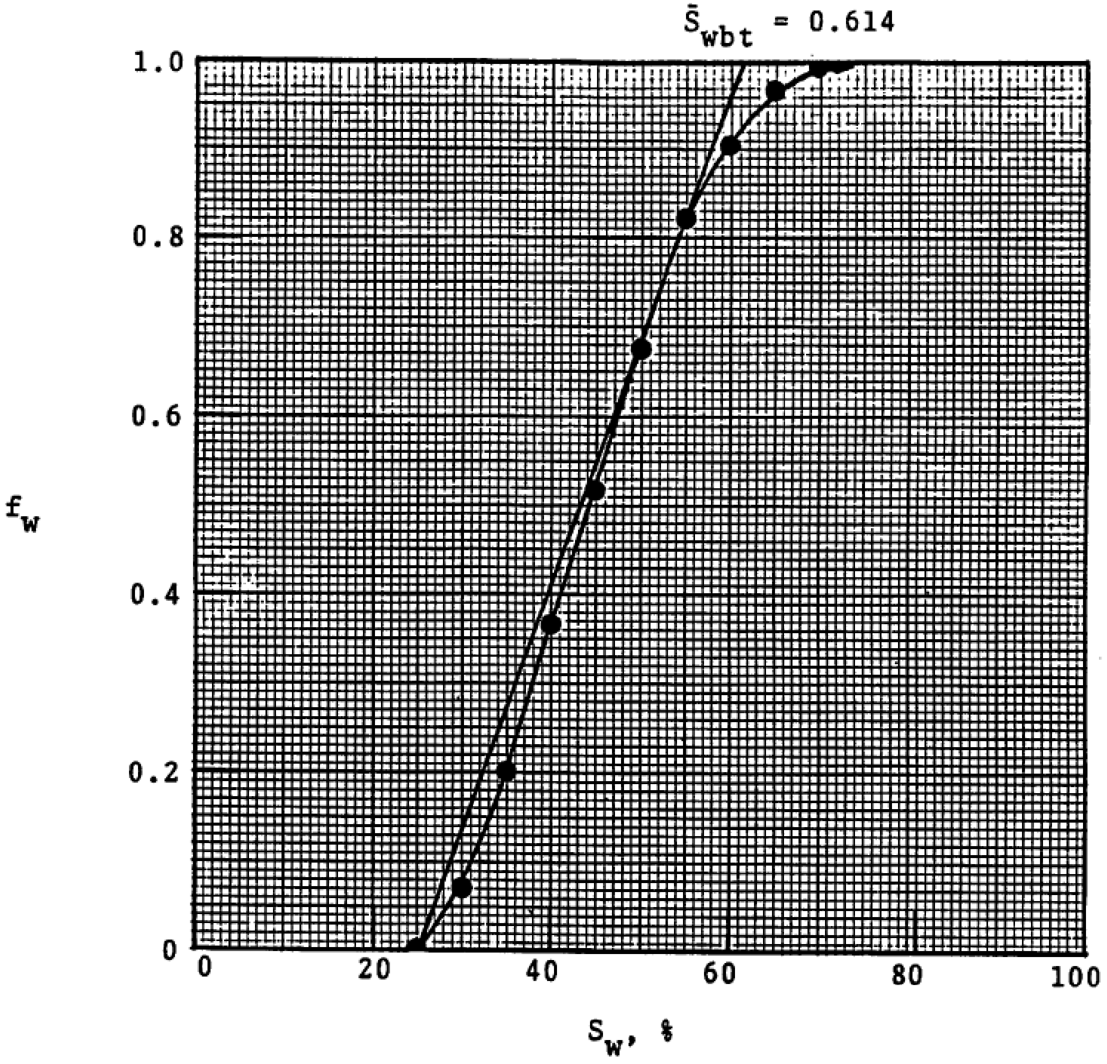


$$f_w = \frac{1}{1 + \frac{k_{ro}}{k_{rw}} \frac{\mu_w}{\mu_o}}$$

The fractional flow data for this reservoir are summarized in the following table:

S_w	f_w	S_w	f_w
0.25	0.000	0.55	0.820
0.30	0.070	0.60	0.905
0.35	0.200	0.65	0.966
0.40	0.365	0.70	0.994
0.45	0.517	0.72	1.000
0.50	0.674		

Waterflooding Class Example



Waterflooding Class Example

a) The oil recovery at breakthrough is determined by:

$$N_{pbt} = \frac{\phi A L}{5.615\ B_o}(\bar{S}_{wbt} - S_{wi})$$

The average water saturation in the reservoir is determined by drawing a line tangent to the fractional flow curve; the intersection of this line with $f_w = 1.0$ defines S_{wbt} . As depicted by the figure, $S_{wbt} = 0.614$ for this reservoir; consequently.

$$N_{pbt} = \frac{(0.22)(78{,}000\ \text{ft}^2)(1320\ \text{ft})}{\left(5.615\ \frac{\text{ft}^3}{\text{bbl}}\right)\left(1.25\ \frac{\text{bbl}}{\text{STB}}\right)}(0.614 - 0.25)$$

$$N_{pbt} = 1.175 \times 10^6\ \text{STB}$$

Waterflooding Class Example

b) Time until breakthrough is determined by:

$$t_{bt} = \frac{\phi A L Q_{ibt}}{5.615 q_t}$$

$$Q_{ibt} = \left(\frac{df_w}{dS_w}\right)_f^{-1} = \bar{S}_{wbt} - S_{wi}$$

$$Q_{ibt} = 0.614 - 0.25 = 0.364$$

$$t_{bt} = \frac{(0.22)(78{,}000)(1320)(0.364)}{(5.615)(7000)}$$

$$t_{bt} = 209.8 \text{ days}$$

Waterflooding Class Example

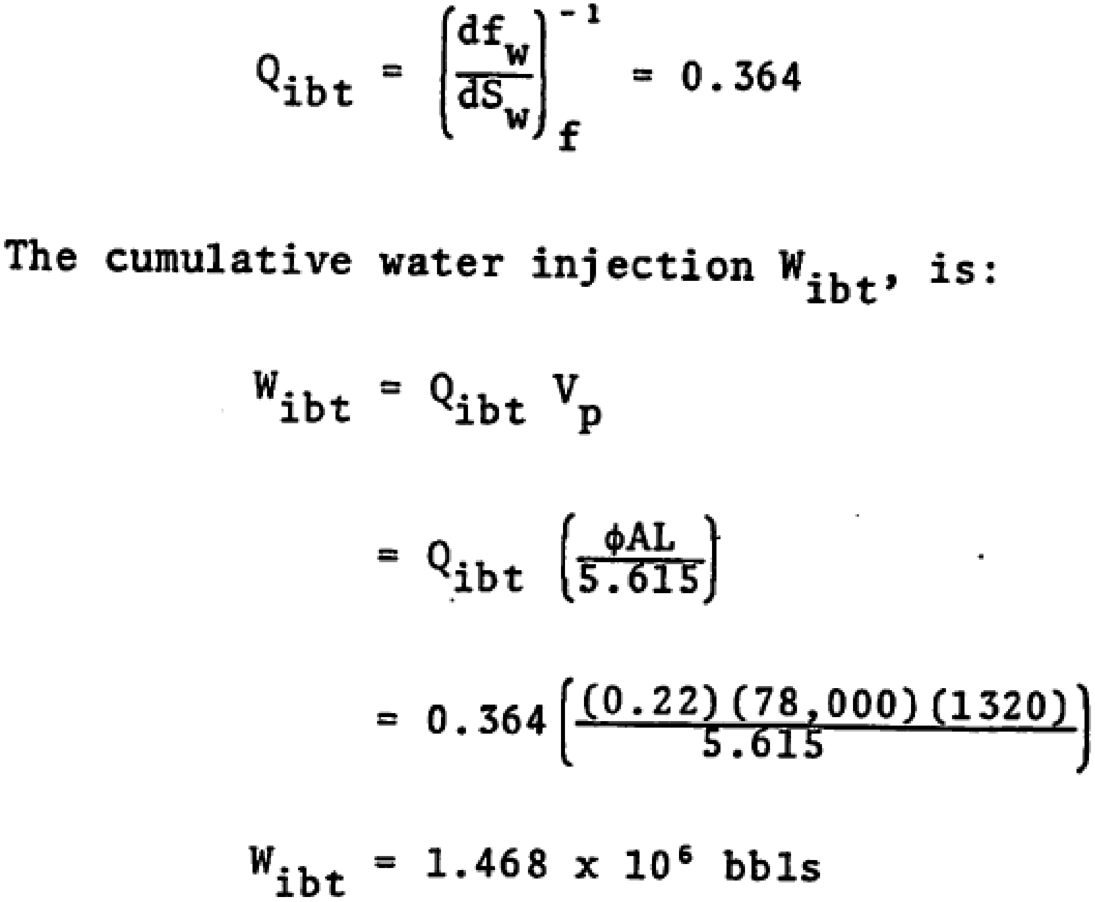
c) The displacement sweep efficiency at breakthrough is defined by:

$$E_{Dbt} = \frac{\bar{S}_{wbt} - S_{wi}}{1 - S_{wi}} = \frac{0.614 - 0.25}{1 - 0.25}$$

$$E_{Dbt} = 0.485$$

Waterflooding Class Example

d) The pore volumes of water injected is defined by:



$$Q_{ibt} = \left(\frac{df_w}{dS_w}\right)_f^{-1} = 0.364$$

The cumulative water injection W_{ibt}, is:

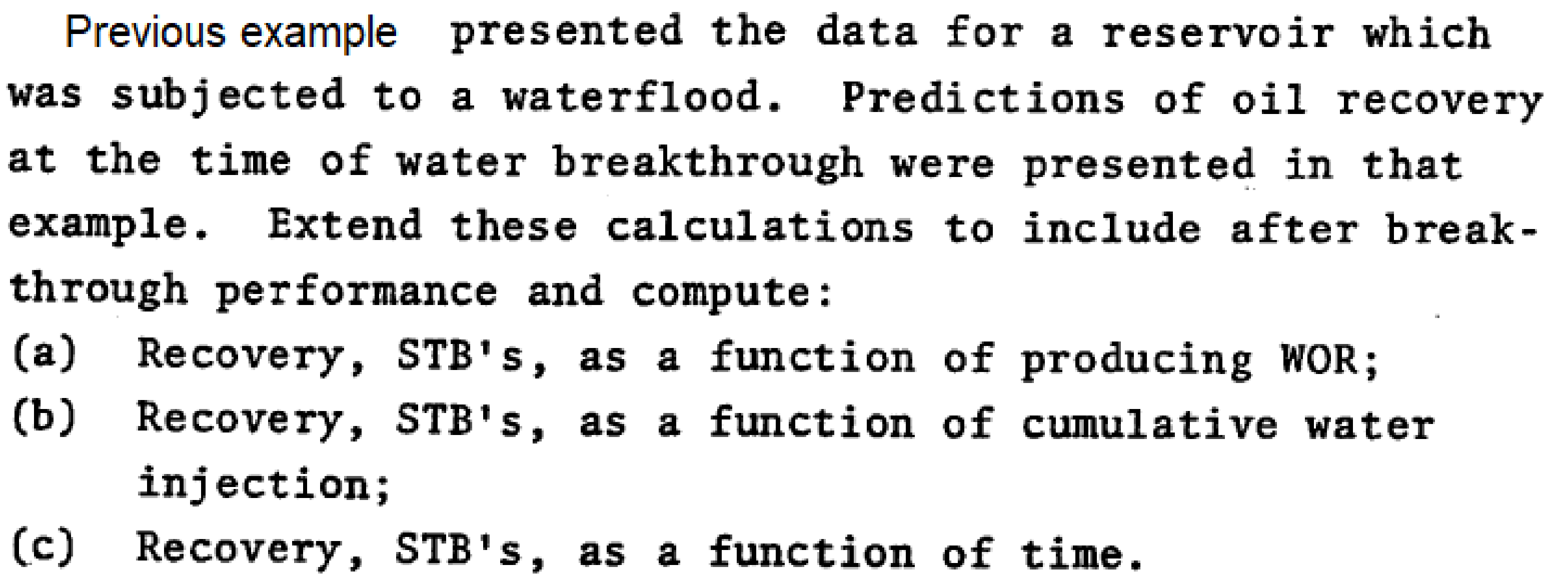
$$W_{ibt} = Q_{ibt} V_p$$

$$= Q_{ibt} \left(\frac{\phi AL}{5.615}\right)$$

$$= 0.364 \left(\frac{(0.22)(78,000)(1320)}{5.615}\right)$$

$$W_{ibt} = 1.468 \times 10^6 \text{ bbls}$$

Waterflooding Class Example



Previous example presented the data for a reservoir which was subjected to a waterflood. Predictions of oil recovery at the time of water breakthrough were presented in that example. Extend these calculations to include after breakthrough performance and compute:

(a) Recovery, STB's, as a function of producing WOR;

(b) Recovery, STB's, as a function of cumulative water injection;

(c) Recovery, STB's, as a function of time.

Waterflooding Class Example

The fractional flow data for this reservoir were computed in previous example and were presented graphically in previous figure. Calculations in previous example resulted in the following information at the time of breakthrough:

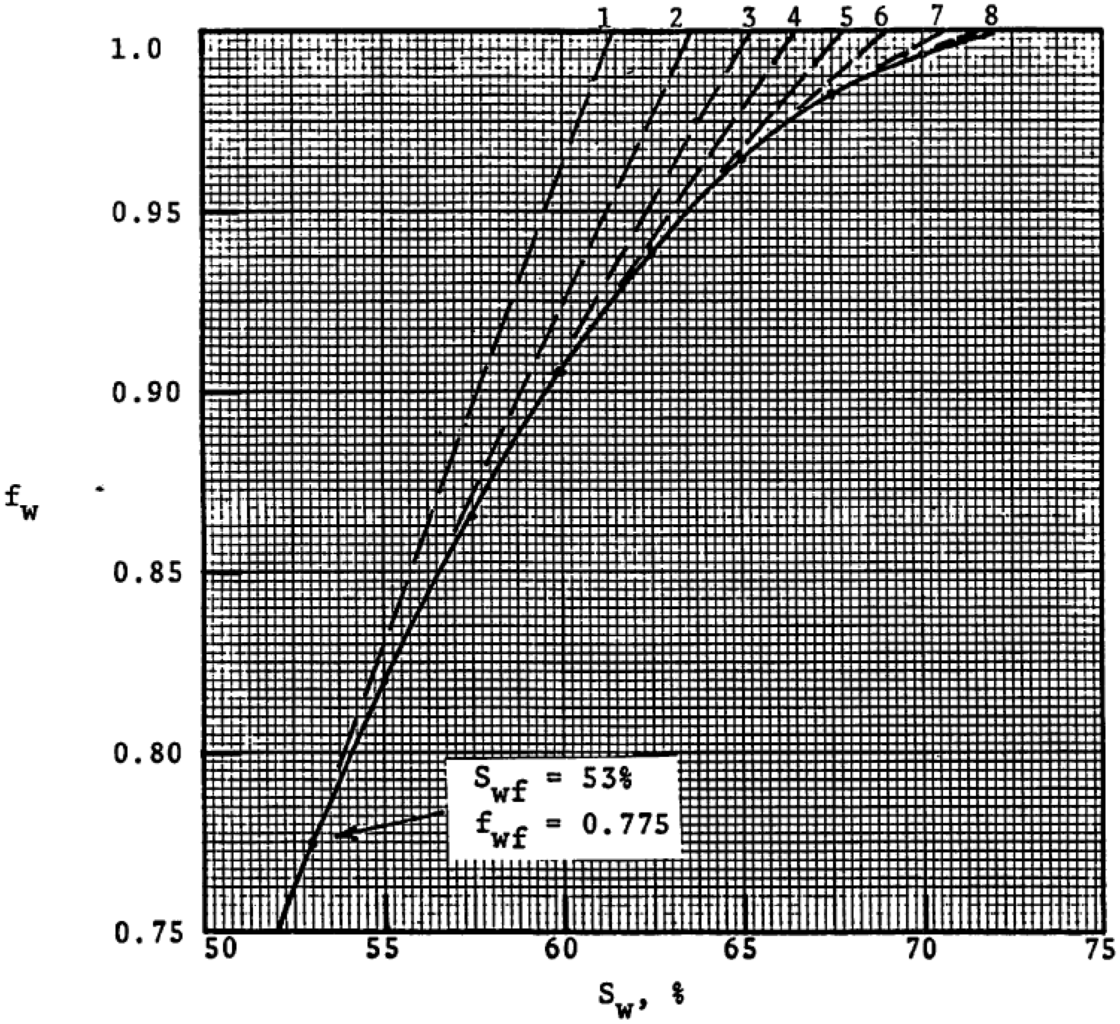
$$N_{pbt} = 1.175 \times 10^6 \text{ STB}$$

$$t_{bt} = 209.8 \text{ days}$$

$$\bar{S}_{wbt} = 0.614$$

$$W_{ibt} = 1.468 \times 10^6 \text{ bbls}$$

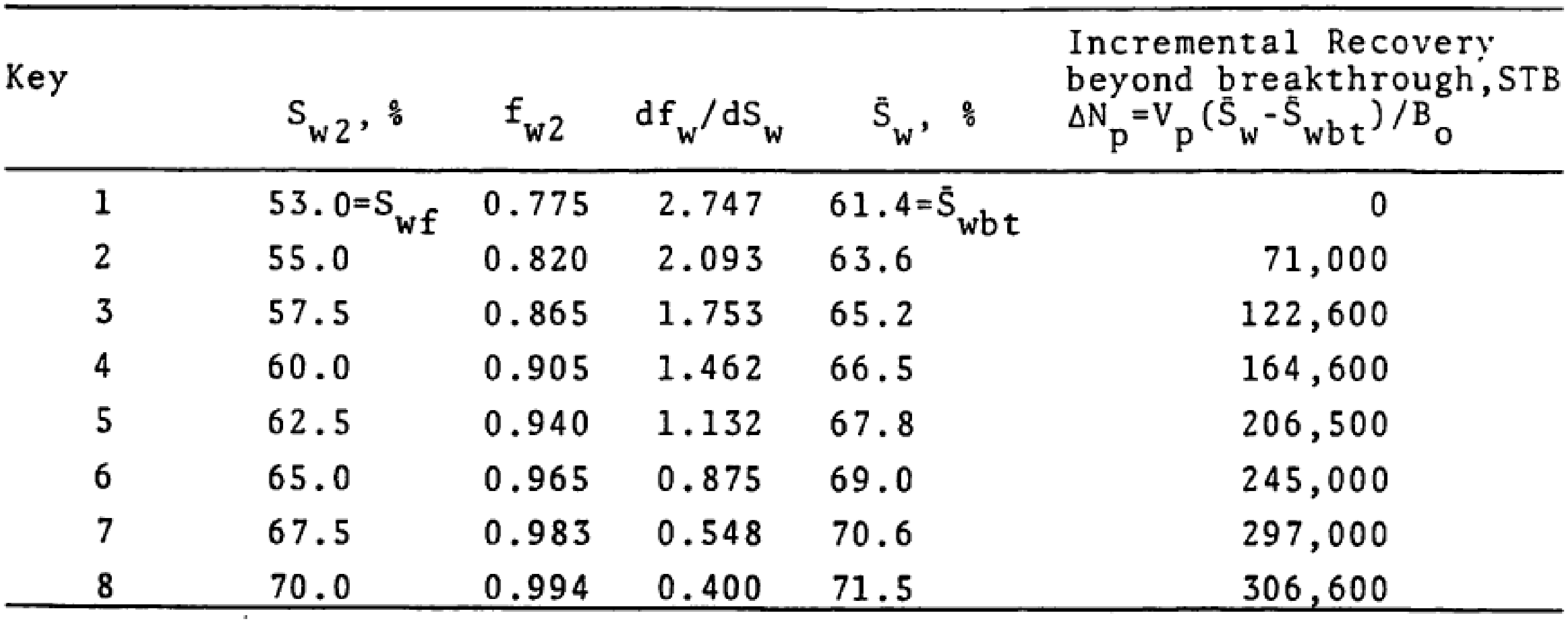
Waterflooding Class Example



Tangent construction to non-stabilized portion of fractional flow curve for calculations beyond breakthrough

Waterflooding Class Example

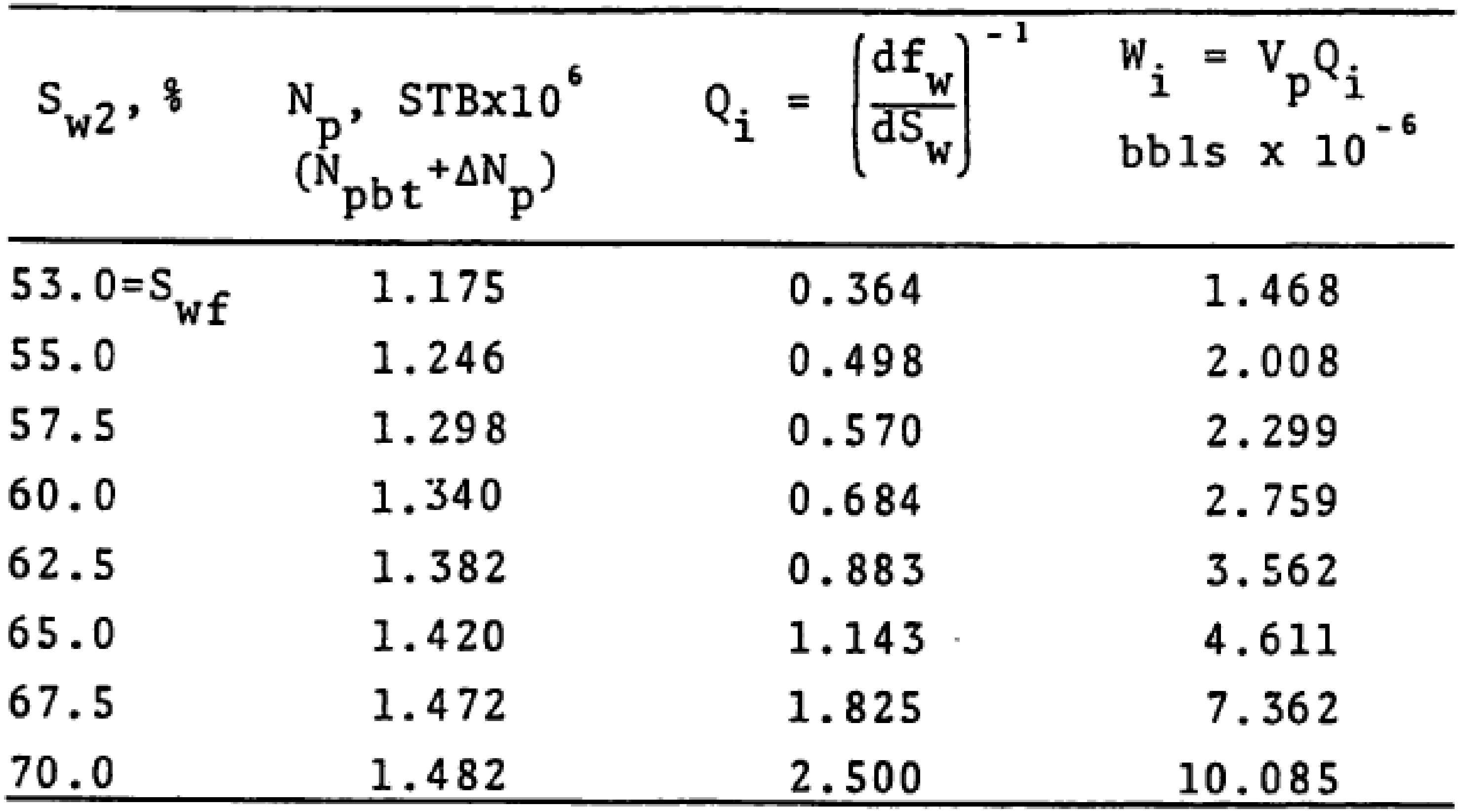
Recovery, STB's, as a function of producing WOR;



Key	S_{w2}, %	f_{w2}	df_w/dS_w	$\bar{S}_w$, %	Incremental Recovery beyond breakthrough, STB $\Delta N_p = V_p(\bar{S}_w - \bar{S}_{wbt})/B_o$
1	53.0=S_{wf}	0.775	2.747	61.4=$\bar{S}_{wbt}$	0
2	55.0	0.820	2.093	63.6	71,000
3	57.5	0.865	1.753	65.2	122,600
4	60.0	0.905	1.462	66.5	164,600
5	62.5	0.940	1.132	67.8	206,500
6	65.0	0.965	0.875	69.0	245,000
7	67.5	0.983	0.548	70.6	297,000
8	70.0	0.994	0.400	71.5	306,600

Waterflooding Class Example

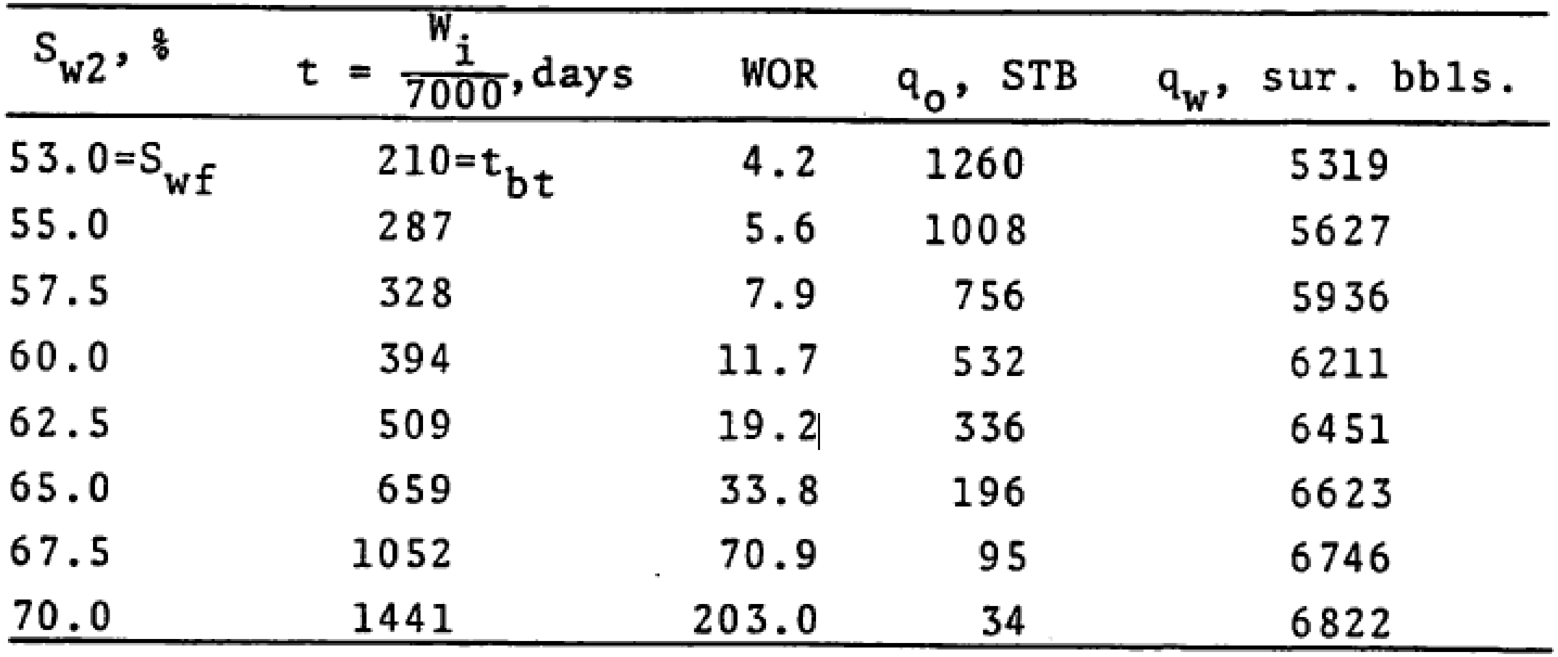
Recovery, STB's, as a function of cumulative water injection;



S_{w2}, %	N_p, STBx10^6 $(N_{pbt}+\Delta N_p)$	$Q_i = \left(\frac{df_w}{dS_w}\right)^{-1}$	$W_i = V_p Q_i$ bbls x 10^{-6}
53.0=S_{wf}	1.175	0.364	1.468
55.0	1.246	0.498	2.008
57.5	1.298	0.570	2.299
60.0	1.340	0.684	2.759
62.5	1.382	0.883	3.562
65.0	1.420	1.143	4.611
67.5	1.472	1.825	7.362
70.0	1.482	2.500	10.085

Waterflooding Class Example

Recovery, STB's, as a function of time;



S_{w2}, %	$t = \frac{W_i}{7000}$, days	WOR	q_o, STB	q_w, sur. bbls.
53.0=S_{wf}	210=t_{bt}	4.2	1260	5319
55.0	287	5.6	1008	5627
57.5	328	7.9	756	5936
60.0	394	11.7	532	6211
62.5	509	19.2	336	6451
65.0	659	33.8	196	6623
67.5	1052	70.9	95	6746
70.0	1441	203.0	34	6822

$$WOR = \frac{q_w B_o}{q_o B_w} = \frac{q_t f_{w2} B_o}{q_t f_{o2} B_w} = \frac{f_{w2}}{1-f_{w2}} \frac{B_o}{B_w}$$

$$q_o = \frac{(1-f_{w2})q_t}{B_o}, \text{ STB/D}$$

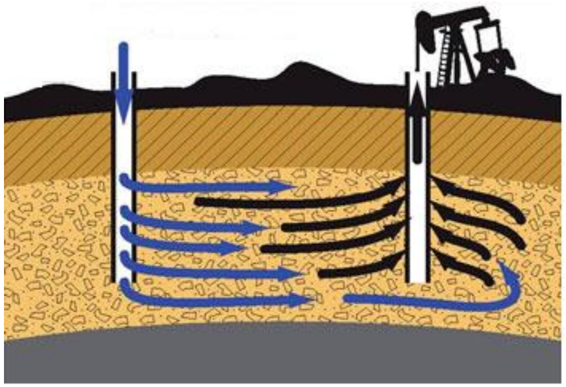
$$q_w = \frac{f_{w2} q_t}{B_w}, \text{ STB/D}$$

References:

- Dr. K. Gizem Gül Ertunç, PETE 443 Lecture Notes
- Dr. Mustafa Onur, PETE 443 Lecture Notes
- Smith J.T. and Cobb W.M., Waterflooding, 1997

PNGE 443
Enhanced Oil Recovery

Chapter 5
Thermal Methods



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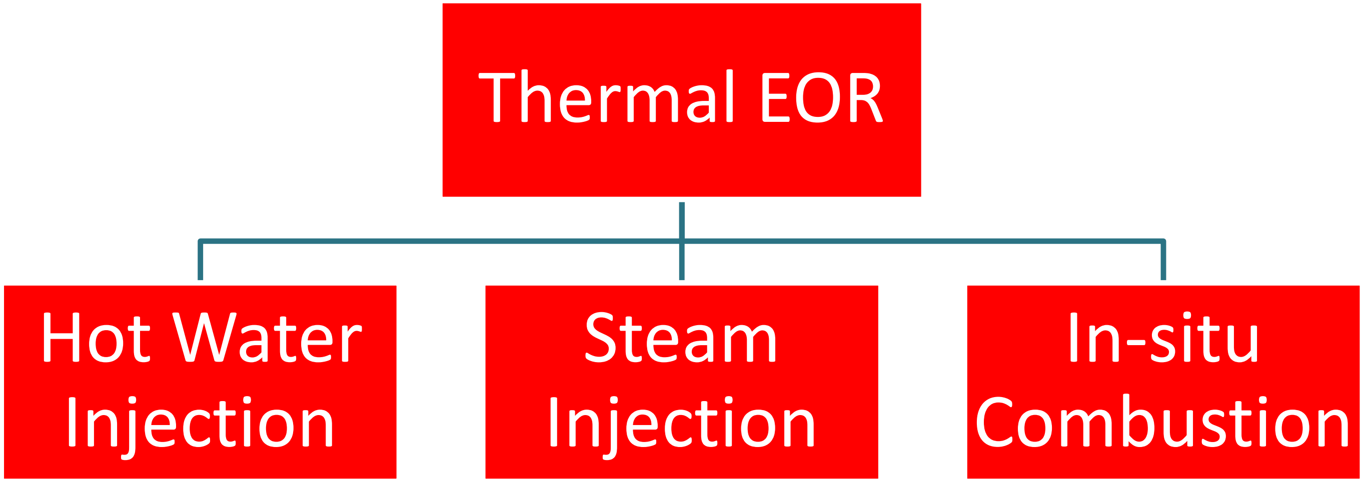
Thermal Methods

- Thermal methods are divided into three types; hot water injection, steam injection and in-situ combustion.



Thermal EOR

Hot Water Injection

Steam Injection

In-situ Combustion

Thermal Methods

- Reduces viscosity
- Decreases density
- Decreases interfacial tension
- Vaporizes oil
- At a greater extent thermally crack the oil
- Increases wetness in some systems
- Used in sandstone formations

Hot Water Injection

Description

- A method of thermal recovery in which hot water is injected into a reservoir through specially distributed injection wells. Hot waterflooding reduces the viscosity of the crude oil, allowing it to move more easily toward production wells. Hot waterflooding, is typically less effective than a steam-injection process because water has lower heat content than steam.
- It is an inefficient operation with high heat losses. It is applied in areas close to the surface.
- It is rarely performed

Hot Water Injection

Limitations/Problems

- The choice of the water-flood parameters: the temperature of injected water, slug volume, injection rate, and starting time, is dictated by the specific geological and physical characteristics of the particular oilfield, after which a hydrodynamic estimate of the efficiency of hot water-flooding in comparison with other methods of enhanced oil recovery must be made.
- Hot water-flooding is particularly effective in the development of fields of high viscosity oils which contain large quantities of paraffins and resinous asphaltene substances.

Steam Flooding

Description

- The steamdrive process or steamflooding involves continuous injection of about 80% quality steam to displace crude oil toward producing wells. Normal practice is to precede and accompany the steamdrive by a cyclic steam stimulation of the producing wells (called huff ’n’ puff).

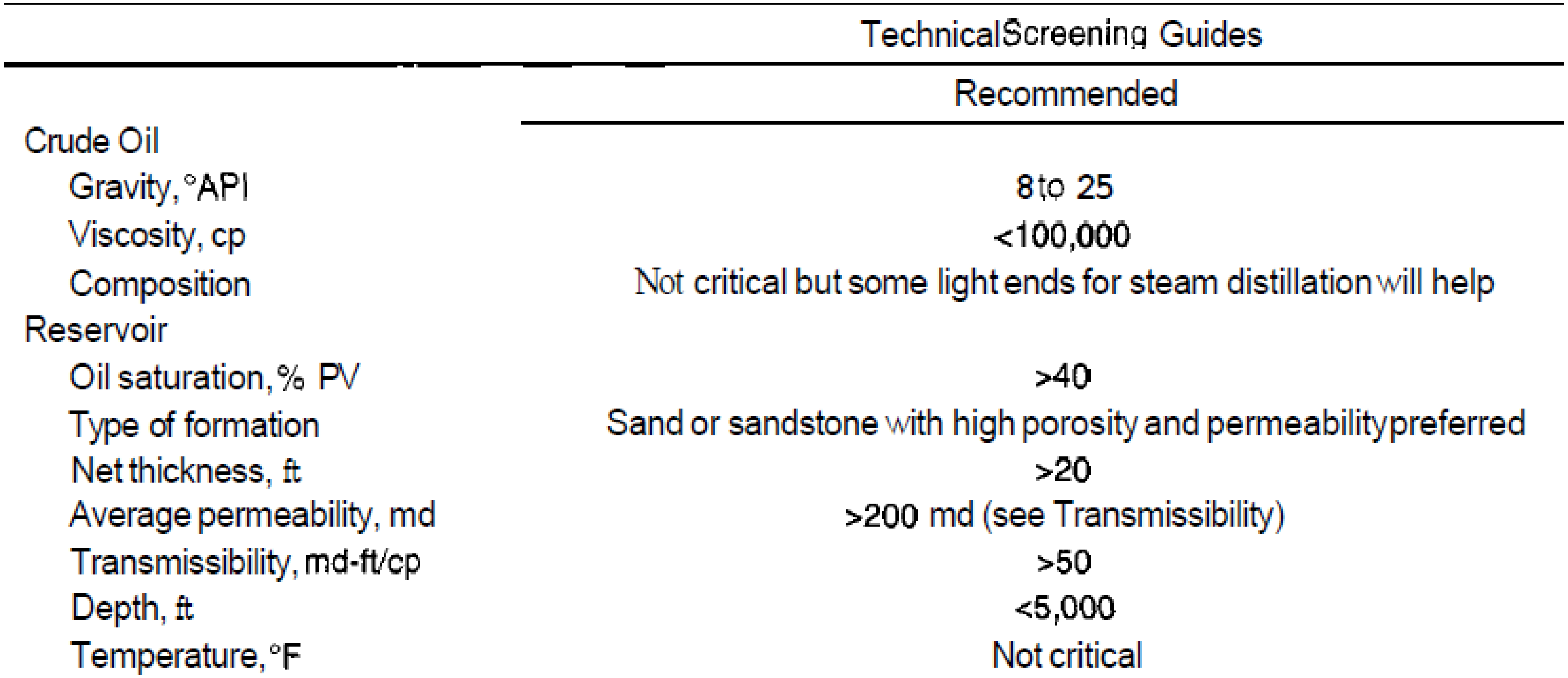
Steam Flooding

Mechanisms

- Steam recovers crude oil by **(1)** heating the crude oil and reducing its viscosity; **(2)** supplying the pressure to drive oil to the producing well; and **(3)** steam distillation, especially in light crude oils

Steam Flooding

Criteria



	Technical Screening Guides
	Recommended
Crude Oil	
Gravity, °API	8 to 25
Viscosity, cp	<100,000
Composition	Not critical but some light ends for steam distillation will help
Reservoir	
Oil saturation, % PV	>40
Type of formation	Sand or sandstone with high porosity and permeability preferred
Net thickness, ft	>20
Average permeability, md	>200 md (see Transmissibility)
Transmissibility, md-ft/cp	>50
Depth, ft	<5,000
Temperature, °F	Not critical

Steam Flooding

Limitations/Problems

- Oil saturations must be quite high, and the pay zone should be more than 20 ft thick to minimize heat losses to adjacent formations. Lighter, less-viscous crude oils can be steamflooded but normally will not be if the reservoir responds to an ordinary waterflood. Steamflooding is primarily applicable to viscous oils in massive, high-permeability sandstones or unconsolidated sands. Because of excess heat losses in the wellbore, steamflooded reservoirs should be as shallow as possible as long as pressure for sufficient injection rates can be maintained. Steamflooding is not normally used in carbonate reservoirs. Because about one-third of the additional oil recovered is consumed to generate the required steam, the cost per incremental barrel of oil is high. A low percentage of water-sensitive clays is desired for good injectivity.

In-Situ Combustion

Description

- In-situ combustion or fireflooding involves starting a fire in the reservoir and injecting air to sustain the burning of some of the crude oil. The most common technique is forward combustion in which the reservoir is ignited in an injection well, and air is injected to propagate the combustion front away from the well. One of the variations of this technique is a combination of forward combustion and waterflooding. A second technique is reverse combustion in which a fire is started in a well that will eventually become a producing well, and air injection is then switched to adjacent wells; however, no successful field trials have been completed for reverse combustion.

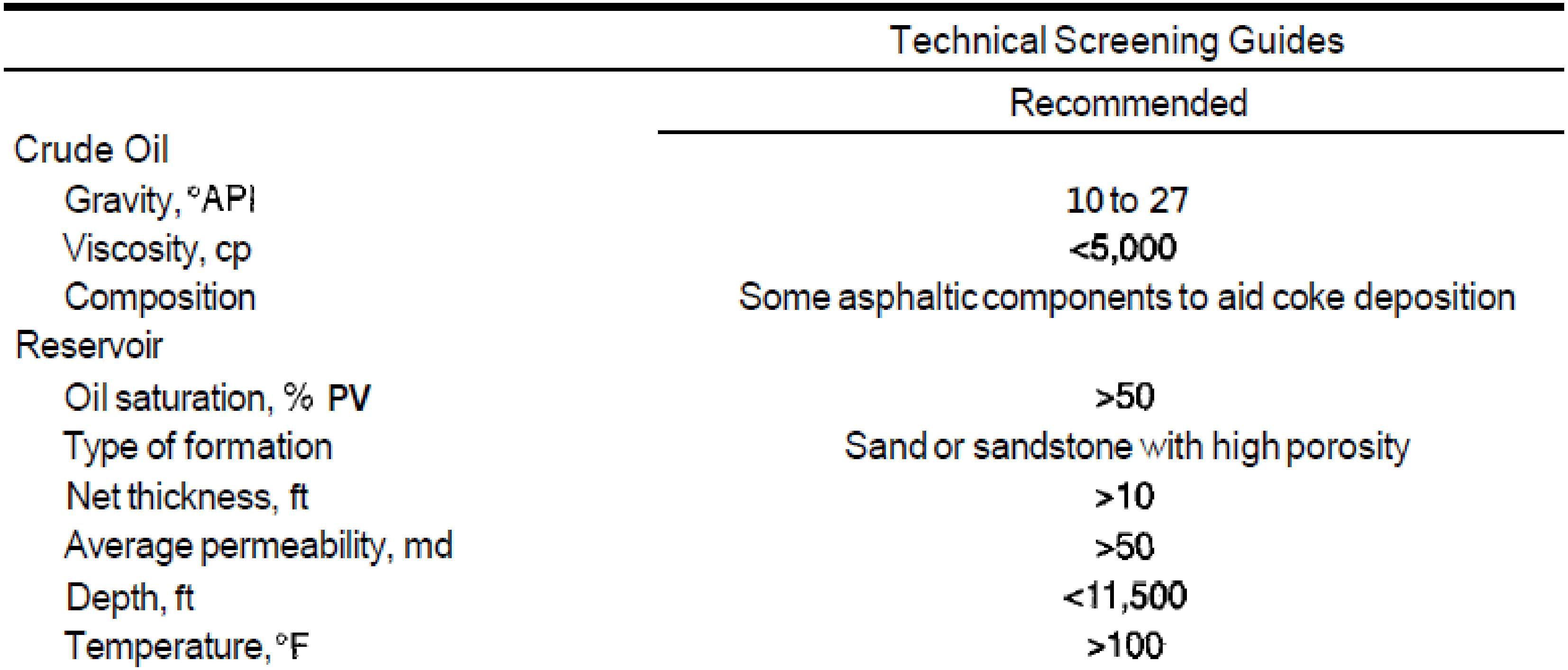
In-Situ Combustion

Mechanisms

- In-situ combustion recovers crude oil by **(1)** the application of heat which is transferred downstream by conduction and convection, thus lowering the viscosity of the oil; **(2)** the products of steam distillation and thermal cracking that are carried forward to mix with and upgrade the crude; **(3)** burning coke that is produced from the heavy ends of the oil; and (4) the pressure supplied to the reservoir by injected air

In-Situ Combustion

Criteria



	Technical Screening Guides
	Recommended
Crude Oil	
Gravity, °API	10 to 27
Viscosity, cp	<5,000
Composition	Some asphaltic components to aid coke deposition
Reservoir	
Oil saturation, % PV	>50
Type of formation	Sand or sandstone with high porosity
Net thickness, ft	>10
Average permeability, md	>50
Depth, ft	<11,500
Temperature, °F	>100

In-Situ Combustion

Limitations

- If sufficient coke is not deposited from the oil being burned, the combustion process will not be sustained; this prevents the application for high-gravity paraffinic oils. If excessive coke is deposited, the rate of advance of the combustion zone will be slow and the quantity of air required to sustain combustion will be high. Oil saturation and porosity must be high to minimize heat loss to rock. Process tends to sweep through upper part of reservoir so that sweep efficiency is poor in thick formations.

In-Situ Combustion

Problems

- Adverse mobility ratio. Early breakthrough of the combustion front. Complex process that requires large capital investment and is difficult to control. Produced flue gases can present environmental problems. Operational problems, such as severe corrosion caused by low-pH hot water, serious oil/water emulsions, increased sand production, deposition of carbon or wax, and pipe failures in the producing wells as a result of the very high temperatures.

In-Situ Combustion

- Three factors control the in-situ combustion process: fuel availability, air requirement and air flux.
- Even small-scale field pilot tests are costly and time-consuming and they can be difficult to interpret. Therefore, the oil industry uses laboratory experiments to develop basic design parameters for field applications. Reservoir conditions are simulated in the laboratory, and steam or combustion drive is applied to the laboratory system. Much information on the combustion characteristics of a formation can be determined through a combustion-tube study.

Thermal Methods

- Thermal recovery methods are the most widely used EOR method in the world. Among them the most widely used recovery method is steam injection and in-situ combustion. Low mobility crude oils are hard to extract. In order to extract them, the viscosity of the crude oil should be reduced. The oil viscosity depends highly on temperature, the increase in temperature causes a decrease in the oil viscosity and therefore, increase in mobility. The temperature in the reservoir system can be increased by injecting hot fluid into the system or burning a portion of oil in place. Heat is applied to the crude oils in order to;
  - reduce the viscosity of the crude,
  - activate a solution gas drive in some instances,
  - result in thermal expansion of the oil and hence increased relative permeability,
  - create distillation and, in some cases, thermal cracking of the oil.

Thermal Methods

- The first industrially significant TEOR project was conducted in 1931 close to Woodson, TX. This was a steam injection test. An advanced steam injection (cyclic steam injection) was later discovered upon release of accrued reservoir fluid pressure through a retrograde flow of injected steam; that coincidentally resulted in considerable oil production instead of the expected steam. Subsequent large-scale TEOR projects were conducted in Tia Juana and Mene Grande fields, both located in Venezuela. Upon discovery of the Venezuelan field (Mene Grande), steam flooding was selected as the optimal TEOR method, and a continuous steam injection over several weeks was deployed, with the wells shut in for short time intervals to support heat transfer within the reservoir.

Thermal Methods

- TEOR, specifically steam injection, and in situ combustion have shown great potential worldwide. Steam injection projects have been reported in USA, Indonesia, Oman, Canada, Venezuela and Russia. Field trials of steam injection have been conducted in Brazil, China, Trinidad and Tobago. CSS has been applied in USA, Canada and Venezuela. ISC projects have been reported in Romania, the USA, Canada and India. Steam assisted gravity drainage (SAGD) is mainly carried out in Alberta, Canada for the recovery of bitumen. SAGD has also been tried in Venezuela, although it has not been very successful.

Thermal Methods – Production Facilities

- To reduce thermal expansion effect, prestressed casings should be used. Casing sizes are larger than 7 in. Most used casings are N80 or P110 casing of 9.19 and 10.36 mm. To improve thermal stability 30-40% silica flour can be added in the cement.

- Thermal-resistant tubings could be type III tubing, hydrogen-resistant tubing, and vacuum tubing. Annulus should be filled with helium or nitrogen to reduce wellbore heat loss. Pumps used in lifting heavy oils are generally rod pumps.

Thermal Methods – Wellbore Insulation

- Design of the well completion for steam injection should be aimed to minimize heat loss to the overburden section. This will benefit the process by (1) maximizing heat delivery to the sand face and (2) avoiding significant overburden heating for environment protection.

- Wellbore insulation is an effective way to achieve this and can be accomplished by either an annulus gas blanket or insulated tubing. A gas blanket is formed by injecting an inert gas (usually nitrogen) into the casing/tubing annulus to push the liquid level down to the reservoir and form a gas-filled section with low thermal conductivity.

Thermal Methods – Sand Control Liner

- The majority of oil sands formations in which steam applications are conducted are generally poorly- or unconsolidated, and sand control is usually required. Slotted liner or wire-wrap screen are two of the most popular choices.

Thermal Methods – Water Treatment

- A lot of water is needed in a steam injection project. Generally, the ratio of water needed to the oil produced is 4 to 5. Water treatment includes sodium exchanger to reduce hardness, and equipment to add chemicals and to remove oxygen.

Thermal Methods

- Before discussing heat transfer mechanisms, it is important to define the physical significance of thermal properties, quantities and concepts to be used;
  - **Heat:** is the amount of thermal energy in a given mass of the material above a prescribed reference temperature and pressure.
  - **Temperature:** is a manifestation of the average kinetic energy of the molecules of a material due to thermal agitation. Temperature is not energy; rather, it is a measure of the thermal energy content of a material.
  - **Heat capacity:** Heat required to increase the temperature of a unit mass of the material by one degree of temperature, while maintaining a constant pressure.
  - **Thermal conductivity:** A material property that indicates the quantity of heat transferred in unit time through the material cross sectional area normal to a unit temperature gradient under steady state conditions and in the absence of any movement of fluid or particles.
  - **Thermal diffusivity:** The ratio of the thermal conductivity to the volumetric heat capacity.

Thermal Methods

- **Latent heat of vaporization:** The amount of heat necessary to change a unit mass of liquid into its vapor without a change in temperature and is numerically equal to the latent heat of condensation.
- **Heat of reaction:** The amount of heat released or absorbed during a chemical reaction per unit mass of reactant.
- **Enthalpy:** The amount of heat per unit mass.
- **Gravitational Potential Energy:** is the energy per unit mass resulting from the position of an element of mass in the earth's gravitational field above a reference plane.
- **Kinetic Energy:** is the energy of an element of mass associated with its motion.
- **Total Energy:** The total energy per unit mass can be considered to be composed of enthalpic and potential components in thermal processes.

Thermal Properties of Fluids

- Understanding of the thermal properties of the steam, reservoir fluid and solid is important for the implementation of the steam flood projects. Estimation of the heat losses and the physical recovery mechanism is important for the implementation of the successful steam flooding project.
- The amount of heat absorbed by the water h_w is called enthalpy and is given by the following relationship;

$$h_w = C_w \left(T_s - T_i\right)$$

C_w = Specific heat of water, BTU/lb-°F
T_s = Saturation temperature, °F
T_i = Initial water temperature, °F
h_w = Enthalpy of saturated water, BTU/lb

Thermal Properties of Fluids

- The specific heat of the saturated water can be approximated by;

$$C_w = 1.3287 - 0.000605T + 1.79*10^{-6}\left(T - 460\right)^2$$

T = Temperature, °R

C_w = Specific heat of water, BTU/lb-°F

- The total heat content of steam is (if 1 lb of saturated water is still heated at the same saturation pressure without change in temperature until it is totally converted into steam, the latent heat of steam, L_v should be added to enthalpy of water);

$$h_s = h_w + L_v$$

h_s = Steam heat content or enthalpy, BTU/lb

L_v = Latent heat of steam or enthalpy of vaporization, BTU/lb

Thermal Properties of Fluids

- In the case of a wet steam with a steam quality of “f_s”, the enthalpy of wet steam is given by;

$$h_s = h_w + f_s L_v$$

- For the determination of steam properties, steam tables are used when it is not available, the following properties were used;

$$T_s = 115.1 P_s^{0.225}$$

$$h_w = 91 P_s^{0.2574}$$

$$L_v = 1318 P_s^{-0.08774}$$

$$h_s = 1119 P_s^{0.01267}$$

$$V_s = 363 P_s^{-0.9588}$$

P_s = Saturation pressure, psia

T_s = Steam temperature, °F

h_w = Enthalpy of saturated water, BTU/lb

L_v = Enthalpy of vaporization, BTU/lb

h_s = Steam enthalpy, BTU/lb

V_s = Volume of dry steam

Thermal Properties of Fluids – Class Example

Calculate the heat required to vaporize 1 lb of water at 20 °C and atmospheric pressure

Solution:

- In order to vaporize water, it must be heated up to 100 °C.
- 20 °C = 527.67 °R
- The specific heat of water at 20 °C;

$$C_w = 1.3287 - 0.000605T + 1.79 * 10^{-6}\left(T - 460\right)^2$$

$$= 1.3287 - 0.000605 * 527.67 + 1.79 * 10^{-6}\left(527.67 - 460\right)^2$$

$$= 1.018 \text{ BTU/lb-°F}$$

Thermal Properties of Fluids – Class Example

- The heat required to heat 1 lb of water from 20 °C to 100 °C (i.e., ΔT = 80 °C = 176 °F);

$$q = (1\ \text{lb})\left(1.018\ \frac{\text{BTU}}{\text{lb-}^\circ F}\right)(176\ ^\circ F) = 179.11\ \text{BTU}$$

- Heat required to vaporize it;

$$\begin{aligned} L_v = h_s - h_w &= 1119 P_s^{0.01267} - 91 P_s^{0.2574} \\ &= 1119 * 14.7^{0.01267} - 91 * 14.7^{0.2574} \\ &= 976\ \text{BTU/lb} \end{aligned}$$

- Total heat required;

$$Q = 179.11 + 976 = 1155.11\ \text{BTU/lb}$$

Heat Transfer Mechanism

- Heat is transferred from high temperature to low temperature as stated by second law of thermodynamics by three mechanisms;
    - Conduction – Transfer of thermal energy between objects when there is a physical contact.
    - Convection – Transfer of thermal energy between an object (usually a fluid) and its surroundings when there is a fluid motion
    - Radiation – Transfer of thermal energy from or to a body by the emission of absorption of electromagnetic radiation. Radiation heat transfer in a reservoir during steam injection is not significant because there is insufficient void space for the electromagnetic radiation to propagate.

Heat Transfer Mechanism - Conduction

- Heat conduction is the process by which heat is transferred through nonflowing materials by molecular collisions from a region of high temperature to a region of lower temperature. Conduction to the overburden and underburden of the reservoir strata can be important when fluid velocities are low. The physical law describing heat conduction known as Fourier’s first law;

$$q_{heat} = -\lambda A \frac{dT}{dx}$$

q_{heat} = Rate of transfer in the x-direction, BTU/hr

λ = Thermal conductivity of material, BTU/hr-ft-°F

A = Area normal to x-direction, ft^2

T = Temperature, °F

x = Length along the direction of heat transfer, ft

Heat Transfer Mechanism - Conduction

- The rate at which the thermal front propagates through the formation by conduction is governed by thermal diffusivity, *D*. The thermal diffusivity is defined as the ratio of thermal conductivity, λ_r, to the volumetric heat capacity of the rock and can be approximated by the following expression;

$$D = \frac{\lambda_r}{\rho_r C_r}$$

D = Thermal diffusivity, ft^2/hour

λ_r = Rock thermal conductivity, BTU/hour-ft-°F

ρ_r = Rock density, lb/ft^3

C_r = Specific heat of the rock, BTU/lbm-°F

$\rho_r C_r$ = Volumetric heat capacity of the rock, i.e., overburden, BTU/ft^3-°F

Heat Transfer Mechanism - Conduction

- The volumetric heat capacity of a fluid saturated formation, M, is often used in thermal calculations;

$$M = \phi\left(S_o\rho_oC_o + S_w\rho_wC_w\right) + \left(1-\phi\right)\rho_rC_r$$

M = Volumetric heat capacity of the formation, BTU/ft^3-°F

ρ = Density at reservoir temperatures, lb/ft^3

C = Specific heat capacity, BTU/lb-°F

S = Saturation, fraction

ϕ = Porosity, fraction

o, w, r = Oil, water, rock matrix, respectively.

Heat Transfer Mechanism - Conduction

- Thermal resistance for conductive heat transfer;

$$R = \frac{\Delta x}{\lambda A}$$

- Thermal conductivity of a porous rock increases with an increase in bulk density, liquid saturation, pressure and saturating liquid thermal conductivity. However, it decreases with an increase in temperature and porosity.

Heat Transfer Mechanism - Convection

- Heat convection is the process by which energy is transferred by a flowing fluid. To express the overall effect of convection, we use Newton's law of cooling;

$$q = hA\Delta T$$

h = Convection heat transfer coefficient, BTU/hour-ft^2-°F

Natural Convection: Without an external source of motion

Forced convection: With an external source of motion. Example: Fan blowing air over a plate

- Thermal resistance for convective heat transfer;

$$R = \frac{1}{hA}$$

Heat Transfer Mechanism - Radiation

- Radiation is the process by which heat is transferred by means of electromagnetic waves.

$$q_r = \sigma A_1 \varepsilon_1 \left(T_1^4 - T_2^4 \right)$$

σ = Stefan-Boltzmann constant = 1.713 x 10^{-9} Btu / ft^2-hr-R^4

ε = Emissivity of the surface

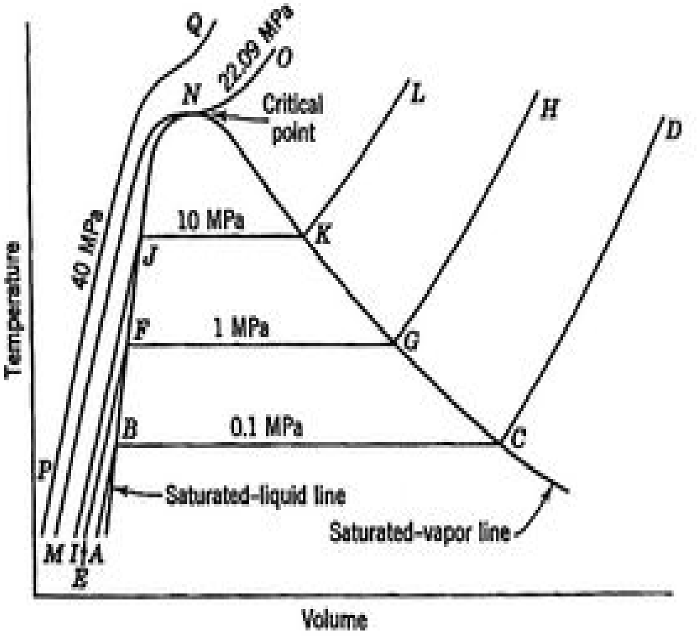
A = Surface area of the subject

- The above equation is called Stefan-Boltzmann law of thermal radiation, and it applies only to black bodies, and valid only for thermal radiation. Real bodies emit radiation at a lower rate than black bodies.

Liquid to Vapor Phase Change

Boiling Point:

- By application of heat, water gains internal energy and the temperature increases (A - B) . When the boiling point, B, is reached, same liquid molecules have enough kinetic energy to escape through the liquid surface tension as vapor. At higher pressures, the boiling temperature increases.



Liquid to Vapor Phase Change

- The amount of heat required to raise the water temperature until the boiling point, B, is reached (change in temperature without a phase change) is called sensible heat, Q_s (J);

$$Q_s = mC\Delta T$$

m = Mass of water, kg or lb

C = Specific heat capacity, J/kg-°C or BTU/lb-°F

ΔT = Temperature difference ($T_1 - T_0$), °C

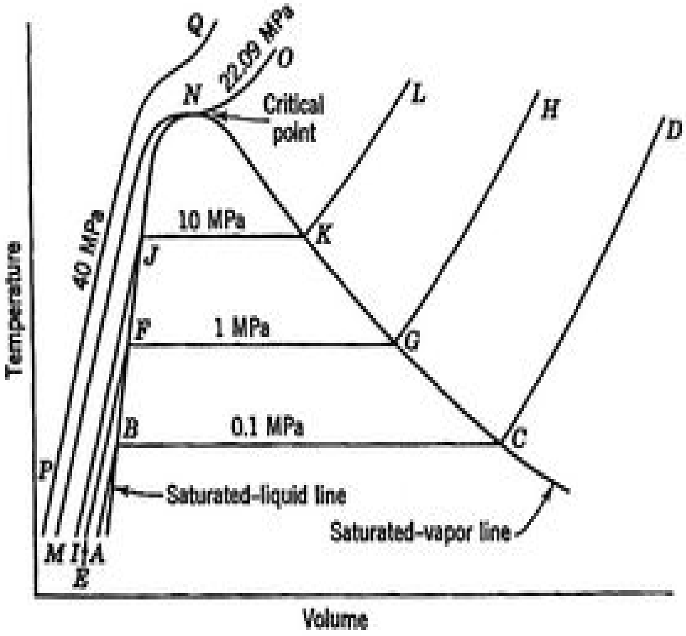
T_1 = Final temperature, °C

T_0 = Initial temperature, °C

Liquid to Vapor Phase Change

Vaporization Point:

- Continued application of heat causes the water to boil and vaporize at a constant temperature and pressure (line B - C). When vaporization point, C, is reached all water in the liquid phase changes to vapor.



Liquid to Vapor Phase Change

Vaporization Point:

- The amount of heat required to change the phase from liquid (water) to vapor (steam) at a constant temperature and pressure is called latent heat of vaporization , L_v (J);

$$L_V = ml_v$$

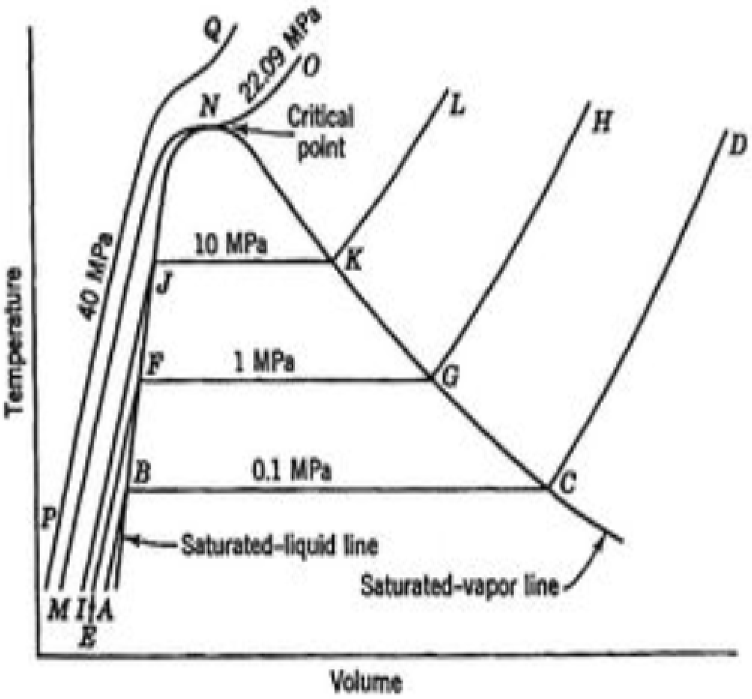
l_v = Enthalpy of vaporization, J/kg or BTU/lb

- Further addition of heat causes the temperature of steam to rise without an increase in pressure. This steam is called superheated.

Liquid to Vapor Phase Change

Water-Steam Pressure-Volume Diagram:

- The line joining points B - F - J with different pressure values is called the bubble point line or saturated liquid line.
- When the liquid is saturated (one phase region) and heat is added, the temperature remains constant, the vaporization process begins and liquid phase changes to vapor phase (B - C, two phases)
- The line joining points C-G-K is called the dew point line or saturated vapor line.
- When the vapor is saturated and heat is added, the temperature increases (C - D, one phase) and the steam is superheated.
- Each A - B - C - D line is also a constant pressure line.

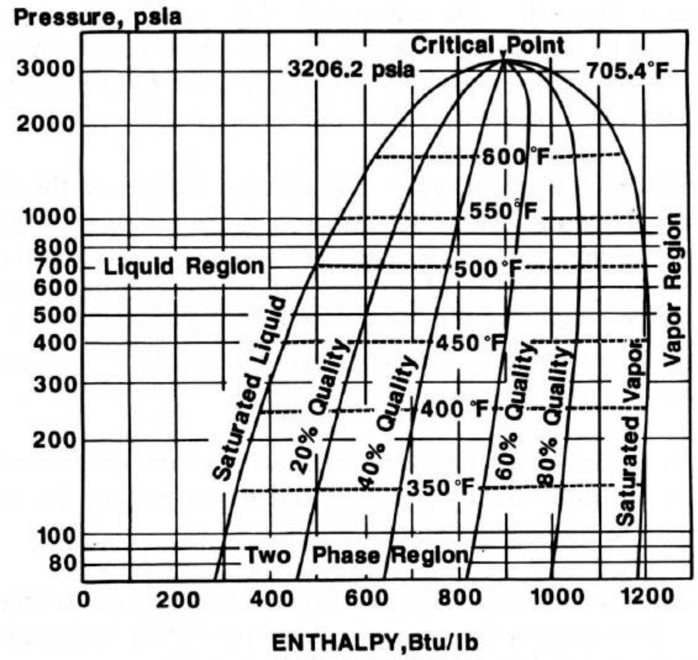


The Heat Content of Steam

- The total amount of heat Q_T absorbed in the process of converting water into steam is given by;

$$Q_T = Q_s + L_V = mC\Delta T + ml_v$$

Steam Enthalpy:



The Heat Content of Steam

- Saturated water has a zero enthalpy value at 0 °C (32 °F) temperature and 0.006 atm (h_{datum} = 0) or 0.08854 psia.
- The amount of heat necessary for a mass unit of at 32 °F and 0.08854 psia to reach the boiling point, B, on the saturation liquid curve is given by the enthalpy of saturated liquid, h_w, J/kg.
- The total enthalpy, h_s, necessary to vaporize all liquid and to reach the point C on vaporization line is;

$$h_s = h_w + L_v$$

L_v = The amount of absorbed heat needed to vaporize the water and is called enthalpy of vaporization at a given saturation temperature and the corresponding pressure (latent heat of vaporization), J/kg

The Heat Content of Steam

- In the field steam generators do not convert all water into steam. Only a certain mass fraction, f_s, of water is converted. Output from the generator is a mixture of saturated water and dry steam. This is called wet steam of quality f_s. The enthalpy of wet steam is;

$$h_s = h_w + f_s L_v$$

- Oil field steam generators produce wet steam usually of 80 to 85 % quality. This means 80 to 85 % of the water mass is vaporized and 10 to 15 % is still in the liquid phase.
- The decrease in the latent heat content of steam becomes larger than the increase of the sensible heat with pressure.

Thermal Methods – Class Example

Find the capacity in tons of steam per hour and the saturation temperature of a 24-MM Btu/hr wet-steam generator operating at 1560 psia saturation pressure and producing steam with f_s=80% quality.

<u>Solution:</u>

Using the pressure enthalpy chart for steam at 1560 psia; the heat content of the wet steam is h_{gw}=1053.7 BTU/lbm

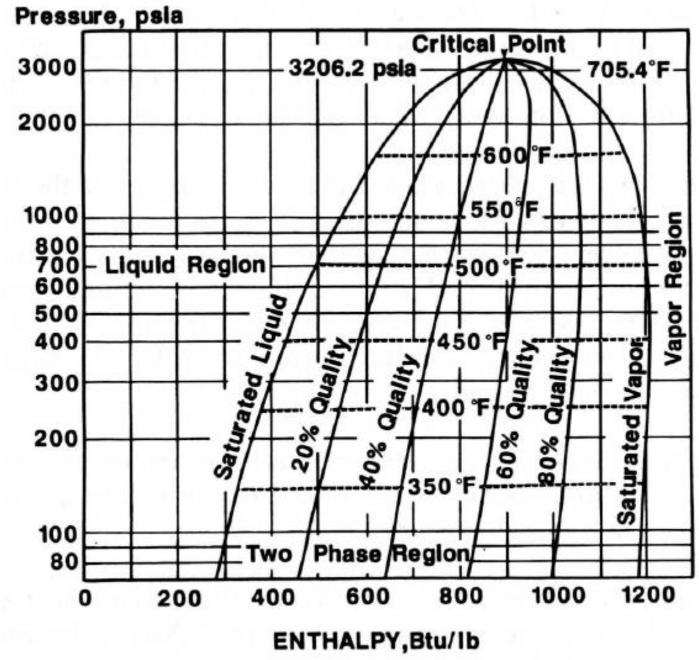
If a 1-lb mass of steam at 1560 psia saturation pressure has 1053.7 Btu, then 1000 kg or 1 ton of steam has

$$\frac{1000 \text{ kg} \times 1053.7 \text{ Btu/lb}_m}{0.4536 \text{ kg/lb}_m} = 2.323 \times 10^6 \text{ Btu}$$

and

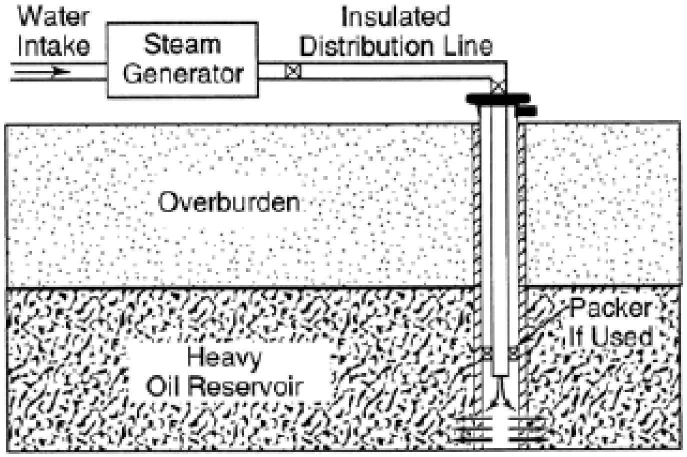
$$24\text{MM Btu/hr} = \frac{24 \times 10^6}{2.323 \times 10^6} \frac{\text{Btu/hr}}{\text{Btu/ton}} = 10.33 \text{ tons/hr of steam}$$

at 1560 psia saturation pressure and 601.43 °F saturation temperature.



Heat Losses

- The amount of formation heated depends on the amount of heat lost
  - In the steam generator
  - From surface pipes
  - From the wellbore
  - To adjacent formations



Heat Loss from Steam Generator

- The heat lost in the steam generator, Q_g, is given by a material balance between the heat released through the fuel-burning process and the heat gained by steam. The total heat, *Q*, liberated by the direct combustion of fuel is;

$$Q = mH$$

H = Heat of combustion or the heat evolved when a unit mass, m of fuel is completely burned, BTU/lb

- The heat gained by steam is;

$$h_s - h_{feed,w} = h_w + f_s L_v - h_{feed,w}$$

- Therefore, the steam generator heat loss is;

$$Q_g = Q - \left[\left(h_w + f_s L_v\right) - h_{feed,w}\right]$$

Heat Loss from Steam Generator

Class Example: A steam generator produces steam of 85 % quality at 1000 psia saturation pressure, consuming 911 lbm/hr fuel oil with 19800 BTU/lbm heat of combustion. The feed water rate is 150 m^3/day at 60 °F. Find the heat loss and the efficiency of the generator.

Solution: From steam table; at P = 1000 psia, h_w = 542.4 BTU/lb and L_v = 649.4 BTU/lb

At 60 °F saturation temperature, $h_{feed,w}$ = 28.06 BTU/lbm

- Total heat produced;

$Q = mH$ = 911 lbm/hr * 19800 BTU/lbm = $18.04*10^6$ BTU/hr

- The change in enthalpy from feed water to wet steam is;

$h_w + f_s L_v - h_{feed,w} = 542.4 + 0.85 * 649.4 – 28.06 = 1066.34$ BTU/lbm

Heat Loss from Steam Generator

- The total heat gained by steam;

150 m^3/day * 1000 kg/m^3 * 2.204 lbm/kg * 1day/24hr * 1066.34 BTU/lbm

= 14.689 x 10^6 BTU/hr

- The heat lost is;

$$Q_g = Q - \left[\left(h_w + f_s L_v \right) - h_{feed} \right] = \left(18.04 - 14.69 \right) * 10^6 = 3.35 * 10^6 \, \mathrm{BTU/hr}$$

- The generator efficiency;

$E = 1 - (Q_g / Q_{in}) = 1 - 3.35*10^6 / 18.04*10^6 = 0.814$ or 81.4 %

Heat Loss from Surface Pipes

- The heat loss from unit length of surface pipe (q_{1s}) is calculated from the temperature difference between the air (T_a) and the fluids in the pipe (T_f) and the overall specific thermal resistance (R_h):

$$q_{1\mathrm{s}} = \frac{T_\mathrm{f} - T_\mathrm{a}}{R_\mathrm{h}}$$

- It is assumed that heat loss rate is steady state, because the transient period is generally short. However, transient state is important during short steam-soak operation. If the temperature of surface is low, radiation is negligible. If there is wind, convection is important. The heat loss from surface pipes is about 1-3% of the injected heat for 1000 m.

Heat Loss from a Wellbore

- The heat loss from a wellbore never reaches a steady state. It attains a quasi-steady state in which the rate of heat loss is a monotonically decreasing function of time. Generally, convection is neglected and the pressure is assumed unchanged. Thus, only steam quality is reduced from the wellhead to the sand face. The calculation equation is similar in form to that for the heat loss from surface pipes, but the thermal resistance R_h is a variable and has to be determined by iteration. The heat loss from wellbores is about 10-20% of the injected heat for 1000 m.

Heat Loss to the Formation

- The heat losses in a steam injection system begin at the steam generator and continue to the surface injection lines, to the wellbore, and to the adjacent strata. The remaining heat is given up to the formation itself and some of it is transported with the fluids produced.
- The beneficial effect of steam injection on oil displacement and recovery depends on the amount of heat transferred to the formation itself and on the porous volume swept by the hot fluids.
- To evaluate this effect the amount of heat loss to adjacent strata must be known.
- Gates and Ramey (1964) and Ramey (1965) have made a graphical comparison of previously derived heat models (Lawerier (1955), Marx and Langenheim (1959), Rubinstein (1959), and Willman et al. (1961)) by plotting on a Cartesian scale the fraction of total heat injected lost to adjacent strata, W_o^*, versus the logarithm of the dimensionless time function, t_D.

Heat Loss to the Formation

- The dimensionless time is;

$$t_D = \frac{4Dt}{h^2}$$

t = Time, days

D = Thermal diffusivity of the cap rock, ft^2/day

h = Formation thickness, ft

- The amount of heat lost to adjacent strata varies directly with time of injection and inversely with formation thickness. So the heat lost can be a high percentage of the cumulative heat injected in a steamdrive process’s lifetime. To reduce the amount of heat lost to adjacent strata, a process of heat scavenging is accomplished by displacing the hot fluids "slug" with cold water injection.

Heat Loss to the Formation

- Gates and Ramey (1964) expressed the cumulative heat loss resulting from injection of hot fluid from time zero to time t_0, followed by injection of cold fluid from time t_0 to time t as;

$$\left(W_0\right)_t = \frac{t}{t_0}\left[\left(W_0^*\right)_t - \left(\frac{t-t_0}{t}\right)\left(W_0^*\right)_{t-t_0}\right]$$

$(W_0)_t$ = Fraction of total heat injected in "slug" up to time t that is lost

t = Total time of injection (hot and cold fluid), days

t_0 = Time heat was injected, days

W_o^* = Obtained from Figure 1 at times t and $t-t_0$

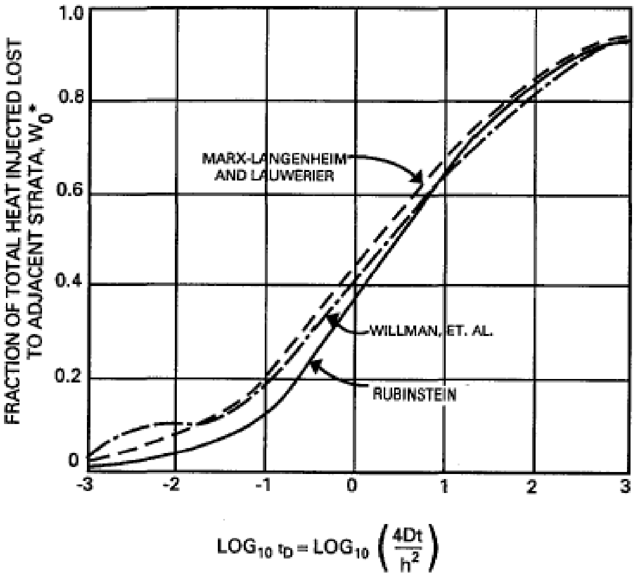


Figure - Vertical heat loss W_o^* versus the logarithm of the dimensionless time function, t_D (From Ramey, 1965)

Steam Injection Processes

- The steam injection is a thermal process in which heat is supplied to the reservoir to increase the reservoir temperature and to deliver necessary energy into the reservoir to displace oil.
- Steam is the heat carrier agent provided by steam generators.
- The steam injected into the reservoir transmits heat to the formation and the fluid contains. The heat lowers the oil viscosity and increases its mobility. As steam cools, it condenses into water.
- Steamdrive uses a pattern flood with injector and producers and continuous steam injection. The main purpose of steamdrive is to increase the ultimate recovery factor.
- Cyclic steam injection is a single well operation, injecting steam and then producing oil from the same well. Cyclic steam injection's principal effect is to stimulate the formation to produce at a higher rate.

Cyclic Steam Stimulation (CSS)

- CCS is a single well process and involves the injection of steam for 2 to 6 weeks into a producing well. After a short soak period of 3 to 6 days, the well produces at a higher rate for several months to a year.
- Steam stimulation is a very useful method for increasing oil production, especially when the reservoir rock is discontinuous. It is also used to stimulate the producers and to cleanup the formation around the wellbore.
- Cyclic steam injection is a method of stimulating well production to obtain higher oil rates , primarily from the first 3 to 4 steam cycles.
- CSS is a precursor to steamdrive in most reservoirs. CSS is preferred when the natural reservoir energy has not been depleted. Steamdrive is used when the reservoir energy is depleted.

Cyclic Steam Stimulation (CSS)

- The essential requirement for successful CSS is a source of natural reservoir energy. Reservoir energy may be available in the form of;
  - fluid expansion by solution-gas drive or reduction in reservoir pressure
  - natural waterdrive
  - gravity drainage
  - compaction.
- A very simple solution for estimating the reservoir response to cyclic steam injection, taking into consideration only its effect on viscosity, was given by Smith (1985).

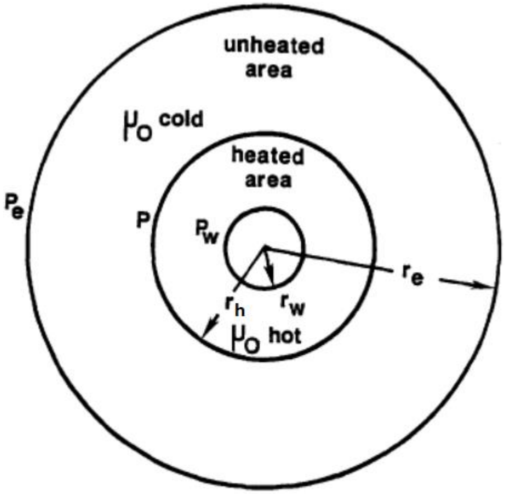
Cyclic Steam Stimulation (CSS)

- The effect of the heated zone on well productivity can be understood by picturing a system of two concentric hollow cylinders of radii r and r_e, with a pressure drop given by;

$$p_e - p_w = (p_e - p) + (p - p_w)$$

$p_e - p_w$ = Pressure drop before the first steam injection cycle (reservoir cold)

$(p_e - p) + (p - p_w)$ = Pressure drop after the steam cycle injection



- A very simple solution for estimating the reservoir response to cyclic steam injection, taking into consideration only its effect on viscosity, was given by Smith (1985). Assuming the radial system of flow as shown in Figure, the heated reservoir extends a distance r_h from the wellbore. The increase in the well's productivity can be calculated by the equation:

$$\frac{q_o^{hot}}{q_o^{cold}} = \frac{\mu_o^{cold} \ln(\frac{r_e}{r_w})}{\mu_o^{hot} \ln\left(\frac{r_h}{r_w}\right) + \mu_o^{cold} \ln(\frac{r_e}{r_h})}$$

Thermal Recovery – Heated Radius

- The remaining heat raises the temperature of the rock and fluids content above the reservoir temperature.
- The heated radius r_h, assuming radial and uniform propagation, can be calculated using;

$$r_h = \sqrt{\frac{Q_f}{\pi M_s \left(T_s - T\right) h}}$$

r_h = Heated radius, ft

Q_f = Net amount of heat available to formation, BTU

M_s = Volumetric heat capacity of steam saturated rock, BTU/ft^3-°F (32 to 38 BTU/ft^3-°F)

T_s = Steam temperature, °F

T = Reservoir temperature, °F

h = Formation thickness, ft

In-Situ Combustion

- ISC is a highly complex process; there is a clear necessity of more initial knowledge and well ahead of time preparation of specialized, dedicated personnel. A total of more than 270 ISC field pilots (more than 200 in the United States) have been conducted in 60 years; probably only 10-20% of them have reached the commercial phase.

- A small portion of the crude oil (5-10%) is burned out furnishing heat to the rock and its fluids.

- The asphaltic crude oil are good candidates for in situ combustion process because the formed coke residues is the principal fuel source to sustain the combustion front.

In-Situ Combustion

- Two main types of ISC are known as; forward combustion and reverse combustion.
- In the first case, burning zone moves with the direction of the injection gas (oxidizing media). In the latter case, burning front moves in the opposite to the oxidizer direction. So far only the forward ISC has reached the commercial application status.

Forward Combustion:

- Forward combustion can be implemented by injection of air (dry burning) and air/water (wet burning). Air and water can be either injected together or sequentially. Single injection well is used in this case.

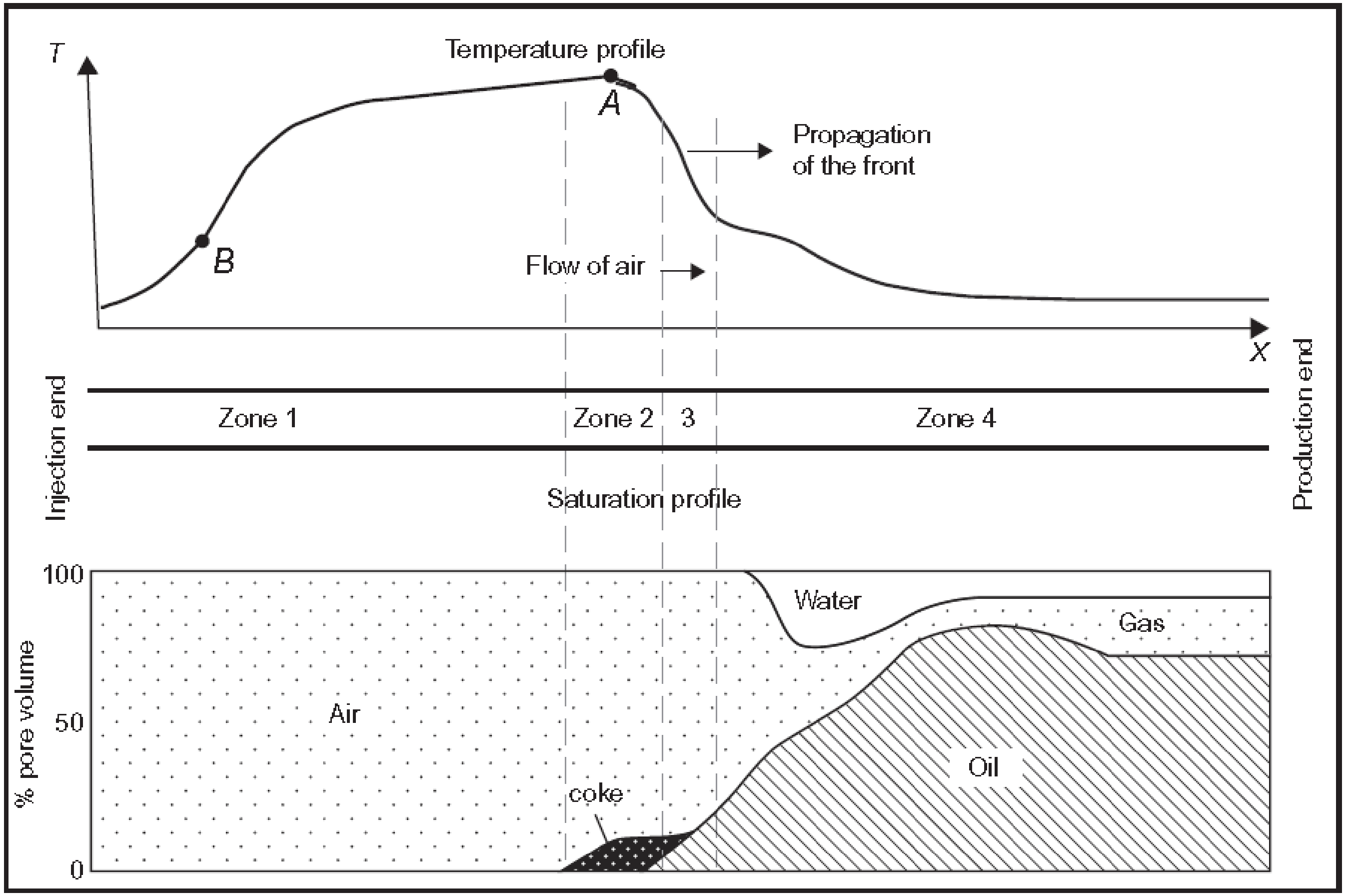
Reverse Combustion:

- Reverse combustion is done by utilization of two injection wells. One well is used to ignite the burning. The second well is used to inject air, which moves towards the burning zone. The oil is then moves towards the first well which needs to be switched to the oil production. The reverse combustion is used for very heavy, immobile oil, where forward combustion does not work.

Wet forward combustion:

- Since the specific heat of the injected air is too low to carry the heat accumulated in the burned zone, more than half of the heat generated remains behind the combustion front. The heat is lost by conduction to the adjacent formations. To achieve a better thermal efficiency, after starting off the process as a dry combustion, water is injected in combination with the injected air. This process is called wet combustion. The wet combustion process is also a combination of forward combustion and waterflood. The burning front velocity, and peak temperatures are identical to normal combustion. The water, however, is flashed to steam, so the steam-front velocity approaches burning front velocity. Heat scavenged from the burned sand is transferred by air and superheated steam to the condensation zone ahead of the combustion front.
- In the field, only dry forward ISC has the status of commercial application; 70-80% dry and only 20-30% wet; in terms of ISC pilots it was a bit different, but generally wet ISC pilots were not developed up to a commercial status except for very few.

In-Situ Combustion



Temperature and saturation profiles during dry ISC process.

Thermal Methods – Class Example

Example: Heat at an amount of 14 MM Btu/hr is injected as wet steam into a formation 70 ft thick for a period of 400 days followed by cold water injection for another 500 days.

The thermal diffusivity, $D = 0.96$ ft^2/day $T_{formation} = 100$ °F

Steam quality = 72% M_s =36 BTU/ft^3-°F

Steam injection pressure = 760 psia at sand face.

Calculate the vertical heat loss to adjacent strata, the net heat gained by the formation and heated radius.

Solution: $t = 400 + 500 = 900$ days and $t_0 = 400$ days

At time t;

$$\log t_D = \log\left(\frac{4Dt}{h^2}\right) = \log\left(\frac{4*0.96*900}{70^2}\right) = -0.15$$

Thermal Methods – Class Example

From Figure , $(W_o^*)_t$ = 0.3
At time *t-t₀*;

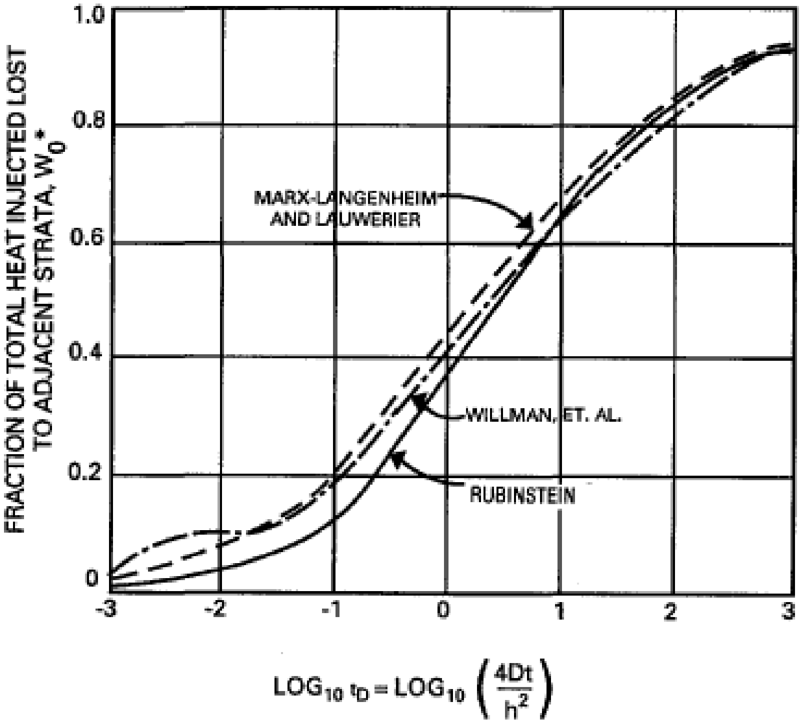
$$\log t_D = \log\left(\frac{4Dt}{h^2}\right) = \log\left(\frac{4*0.96*500}{70^2}\right) = -0.40$$

From Figure 1, $(W_o^*)_{t-t_0}$ = 0.22
Vertical heat loss is;

$$(W_0)_t = \frac{t}{t_0}\left[\left(W_0^*\right)_t - \left(\frac{t-t_0}{t}\right)\left(W_0^*\right)_{t-t_0}\right]$$

$$= \frac{900}{400}\left[0.30 - \left(\frac{900-400}{900}\right)(0.22)\right]$$

$$= 0.40$$



or 40% of the total heat injected into the formation is lost to the adjacent strata.
At time *t*;

Thermal Methods – Class Example

From steam tables, at P_s = 760 psia and 72% steam quality; T_s = 512.3 °F

The wet steam enthalpy;

$$h_s = h_w + f_s L_v = 502.6 + 0.72 * 697.1 = 1004.5 \text{ BTU/lbm}$$

The water enthalpy at 100 °F = 67.9 BTU/lbm

The net enthalpy of the wet steam injected into the formation is;

$h_s - h_{f,water}$ = 1004.5 – 67.9 = 936.6 BTU/lbm

$h_{f,water}$ = Enthalpy of water at reservoir temperature

Steam injection rate is;

$$q_s = \frac{14*10^6\, {}^{BTU}\!\big/_{hr}\; 24\, {}^{hr}\!\big/_{day}}{350\, {}^{lbm}\!\big/_{bbl}\; 1004.5\, {}^{BTU}\!\big/_{lbm}} = 955.7\, bbl/day$$

Available heat above reservoir temperature is;

$$Q_{ah} = \frac{955.7 * 350 * 936.6}{24} = 13\, MMBTU/hr$$

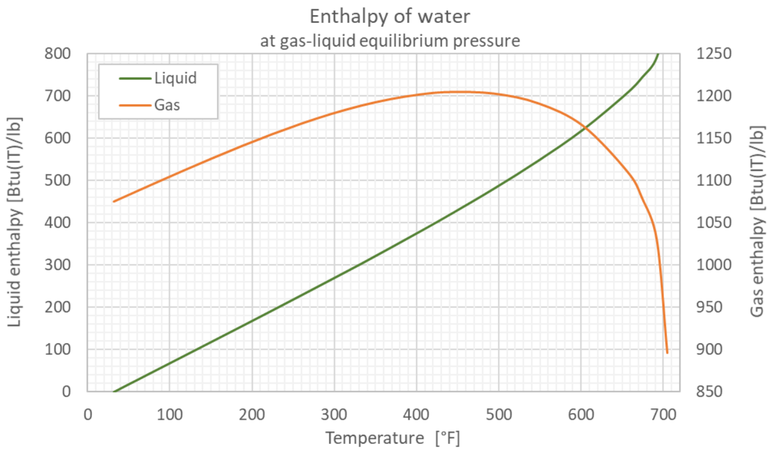
Heat lost to the overburden is;

$Q_{ov} = 0.40 * 13 * 10^6$ = 5.2 MMBTU/hr

Net heat to formation is;

$Q_f = Q_{ah} - Q_{ov} = (13 - 5.2) * 10^6$ = 7.8 BTU/hr

Q_f = 7.8 BTU/hr * 24 hr/day * 400 days = $74.88*10^9$ BTU



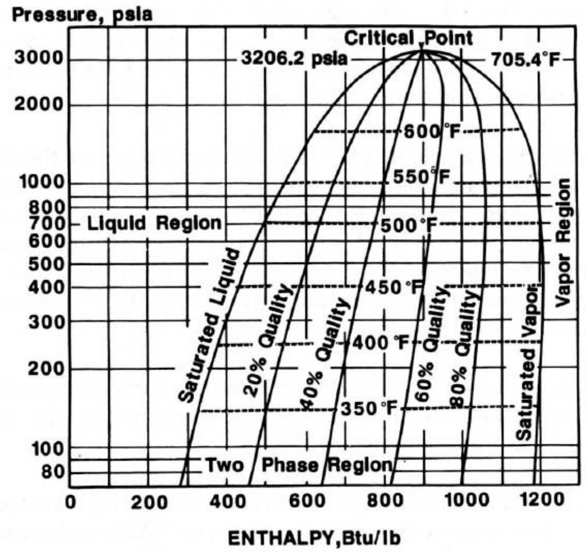
Thermal Methods – Class Example

The heated radius is;

$$r_h = \sqrt{\frac{Q_f}{\pi M_s \left(T_s - T\right) h}}$$

$$= \sqrt{\frac{74.88\ \text{BTU}}{\pi * 36\ \ \text{BTU}/\text{ft}^3 - {}^\circ\text{F} * \left(512.3 - 100\right)\ {}^\circ\text{F} * 70\ \text{ft}}}$$

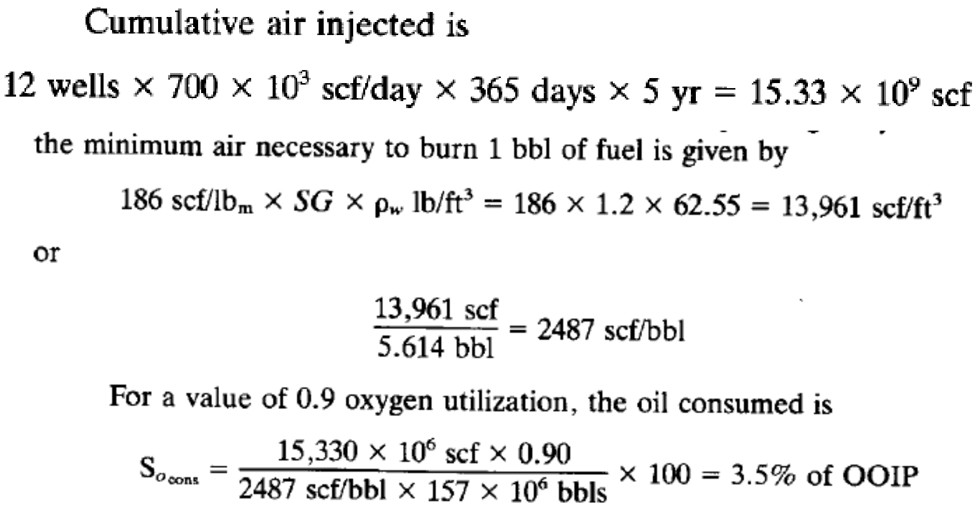
$$= 151.5\ \text{ft}$$



Thermal Methods – Class Example

Calculate the oil consumed after 5 years of in-situ combustion developed as a primary recovery method. The oil reservoir has 157x10^6 bbl OOIP reserve, and the combustion process is sustanied by the injection of 700x10^3 ft^3 air/day through each of the 12 injection wells (assuming 90% combustion efficiency, coke's specific gravity = 1.2, water reference density=62.55 lbm/ft^3 and minimum air necessary to burn 1 pound of fuel 186 scf/lbm).

Solution:



Cumulative air injected is

$$12 \text{ wells} \times 700 \times 10^3 \text{ scf/day} \times 365 \text{ days} \times 5 \text{ yr} = 15.33 \times 10^9 \text{ scf}$$

the minimum air necessary to burn 1 bbl of fuel is given by

$$186 \text{ scf/lb}_m \times SG \times \rho_w \text{ lb/ft}^3 = 186 \times 1.2 \times 62.55 = 13{,}961 \text{ scf/ft}^3$$

or

$$\frac{13{,}961 \text{ scf}}{5.614 \text{ bbl}} = 2487 \text{ scf/bbl}$$

For a value of 0.9 oxygen utilization, the oil consumed is

$$S_{o_{\text{cons}}} = \frac{15{,}330 \times 10^6 \text{ scf} \times 0.90}{2487 \text{ scf/bbl} \times 157 \times 10^6 \text{ bbls}} \times 100 = 3.5\% \text{ of OOIP}$$

Thermal Methods – Class Example

How much pore volume of hot water at 300 ^oF is required to heat a sandstone of 25% to 300 ^oF from 80 ^oF?

Volume basis = 1 acre-ft

$(C_p\rho)_{rock}$= 35 Btu/ft^3.^oF

Solution:

35 Btu/ft^3.^oF x 43560 x (300-80)= 33.5 x 10^7 Btu

Volume of water in 25% porosity

43560 x 0.25 = 10890 ft^3/acre. ft ^oF

Heat required from 300 ^oF hot water when it cools to 80 ^oF:

Btu/PV of water = 10890 ft^3/acre. ft ^oF x 62.4 lb/ft^3 x 1 BTU/lb.^oF x (300-80)

Amount of water required= [(300-80)x35x43560] / [43560x(300-80)x0.25x62.4]

Amount of water required= 2.8 PV of water at 300 ^oF is necessary

Thermal Methods

How much SCF of 500 ^oF of gas is required to heat 1 acre-ft of reservoir rock from 70 ^oF to 500 ^oF, sandstone with 25% porosity? (air density= 29 lbm/379 SCF)

Volume basis = 1 acre-ft

$(C_p\rho)_{rock}$= 35 Btu/ft^3.^oF

<u>Solution:</u>

For 1 acre.ft/35 Btu/ft^3.^oF x 43560 ft^3/acre.ft x (500-70)= 655 x 10^6 Btu/acre.ft

Gas at 500 ^oF

C_p≈0.25 Btu/lbm.^oF $(C_p\rho)_{rock}$= 0.25 Btu/ft^3.^oF x 29 lbm/379 SCF

Heat available = 0.25 x 29/379 x (500-70) = 8.2 Btu/SCF

SCF of gas necessary = 655.10^6 / 8.2 = 79.10^6

Thermal Methods – Class Example

Calculate the productivity increase of a well which produces 13 API crude oil from reservoir with 1100 cp initial viscosity, assuming after the first cycle of steam injection and no change in API gravity that

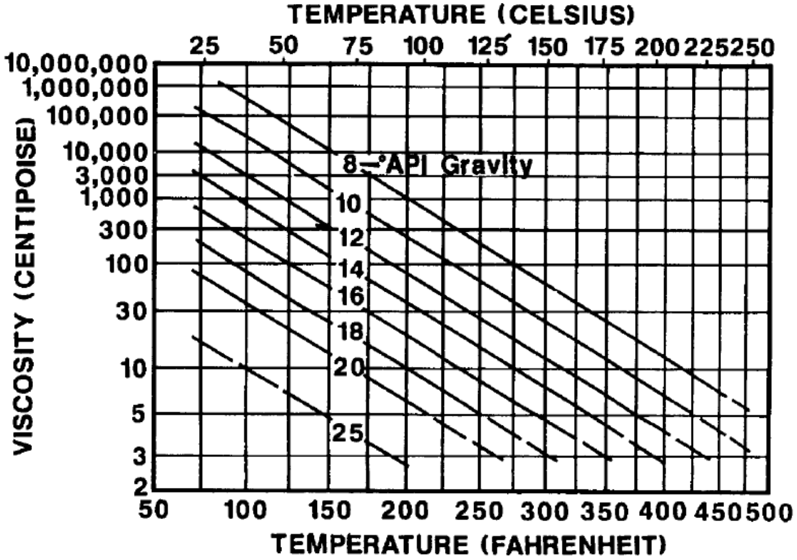
Heated radius	47 ft
Reservoir temperature	100 °F
Reservoir temperature of heated area	300 °F
Drainage Radius	700 ft
Wellbore Radius	0,29 ft

Thermal Methods – Class Example

Solution: The temperature-viscosity relationship for the oil reservoir in the figure shows that oil viscosity in the heated zone decreases to 10 cp. The increase in the well's productivity (due to the viscosity decrease) is

$$\frac{q_o^{hot}}{q_o^{cold}} = \frac{\mu_o^{cold}\ln(\frac{r_e}{r_w})}{\mu_o^{hot}\ln\left(\frac{r_h}{r_w}\right) + \mu_o^{cold}\ln(\frac{r_e}{r_h})}$$

$$\frac{q_o^{hot}}{q_o^{cold}} = \frac{1100\ \ln(\frac{700}{0{,}29})}{10\ln\left(\frac{47}{0{,}29}\right)+1100\ln(\frac{700}{47})}\text{=2,83 times}$$



Enhanced Oil Recovery

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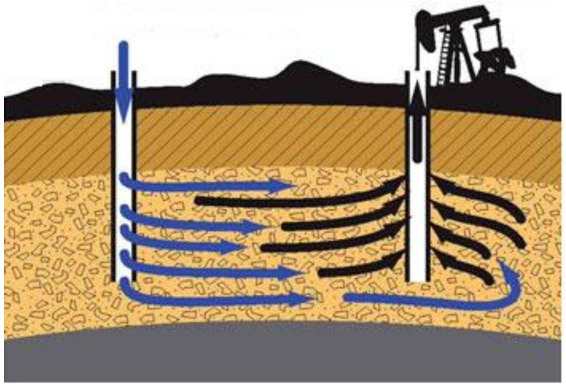
PNGE 443
Enhanced Oil Recovery

Chapter 6
Gas Injection Methods



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Gas Flooding

Description

- Gas flooding is the injection of hydrocarbon or nonhydrocarbon components into oil reservoirs.
- Injected components are usually vapors (gas phase) at atmospheric temperature and pressure and may include mixtures of hydrocarbons from methane to propane, and nonhydrocarbon components such as carbon dioxide, nitrogen, and even hydrogen sulfide or other exotic gases such as SO_2.
- Gas injection today often means CO_2 or rich hydrocarbon gas injection to recovery residual oil, and in some cases to also store or sequester CO_2 from the atmosphere.
- Gas injection can be applied in both sandstone and carbonate formations.

Gas Flooding

Description

- The primary mechanism for oil recovery by high pressure gas flooding is through mass transfer of components in the oil between the flowing gas and oil phases, which increases when the gas and oil become more miscible.

- Secondary recovery mechanisms include swelling and viscosity reduction of oil as intermediate components in the gas condense into the oil.

Gas Flooding

- CH_4 Injection

  - It is a method used in adjacent areas where gas contains.

- N_2 Injection

  - It is a method used in fields containing light oil found in very deep formations. It is rarely used.

- CO_2 Injection

  - It is a widely used method. It is preferred because it increases the mobility of oil more easily and it has environmental advantages.

Gas Flooding

- Other important key technical factors are the average reservoir pressure, minimum pressure for miscibility, and the oil viscosity. The reservoir pressure must usually be near or above the minimum pressure for miscibility to achieve good displacement efficiency. The MMP (minimum miscibility pressure) is typically smaller for low viscosity oils. Rough “rules of thumb” for oils with bubble-point viscosities less than about 10 cp and an API oil gravity of 25 or greater are that CO_2 or enriched gases become miscible with the oil when the reservoir pressure is above 1000 psia, while methane can become miscible with light oils at pressures greater than about 3000 psia, and nitrogen at pressures greater than about 5000 psia. Of course, reservoir temperature and oil composition play an important role in this assessment as well. The miscible fluid chosen should be available and less costly than other alternatives.

Gas Flooding

History

- Gas injection was first developed in the United States, where it is still largely applied. Gas injection is one of the oldest fluid injection processes implemented for pressure maintenance. The first gas injection project was a pressure maintenance job initiated in 1864, after drilling the Drake well in Titusville, Pennsylvania. The project was aimed at boosting fast oil production. In 1930, the earliest gas drive project was successfully performed in West Texas. In the 1970s, another gas injection trial was performed at the Surry County, Texas. In the past two decades, gas injection has gained significant interest and recent projects are focused in combining hydrocarbon recovery with CO_2 geo-storage. Geological storage of CO_2 (CO_2-EOR) is one of the most promising technologies for promoting ultimate oil recovery, while it simultaneously alleviates the problem of greenhouse gas accumulation in the atmosphere. CO_2 -EOR has been extensively deployed since the mid-1980s in the Permian Basin of West Texas with high profit margins achieved over the past three decades.

Gas Flooding

Field Applications

- CO_2, N_2 and hydrocarbon gases are used in GEOR. Technically, the injection of carbon dioxide (CO_2) and hydrocarbon gases achieve higher oil recovery efficiencies. However, natural gas is expensive and there is growing concern about its impact as greenhouse gas; thus, CO_2 is considered the most appropriate gas for injection, although oil recovery using CO_2 is also a costly venture. Certain costs are often associated with its deployment such as: (a) cost of the CO_2 itself which can add about $20–30 per barrel of oil produced; (b) cost of surface facilities for separation of the CO_2 from the production streams and compressing it back into the oil reservoir; and (c) financial costs for the time delay associated with the re-pressurising of old reservoirs. The application of CO_2 for EOR purposes appears to be dependent on oil prices.

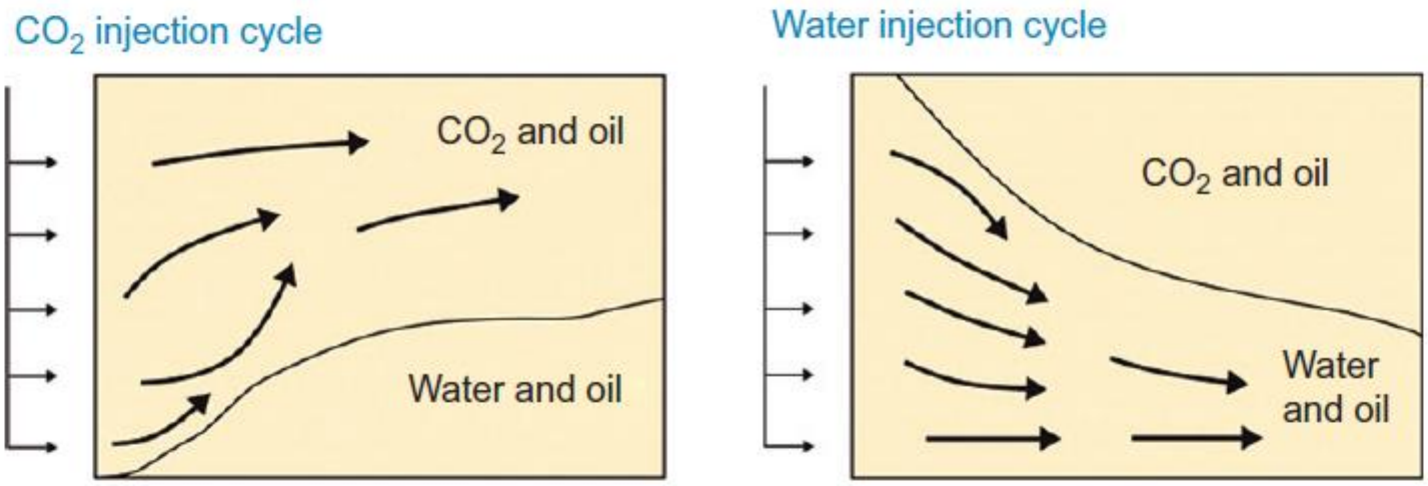
Gas Flooding

Technological Advancements

- Advances in gas injection EOR include water alternate gas (WAG) injection; the simultaneous water alternate gas injection (SWAG), polymer water alternate gas (PWAG) injection, the development of CO_2 gas membrane separation technology and field applications of immiscible gas-assisted gravity drainage (GAGD).

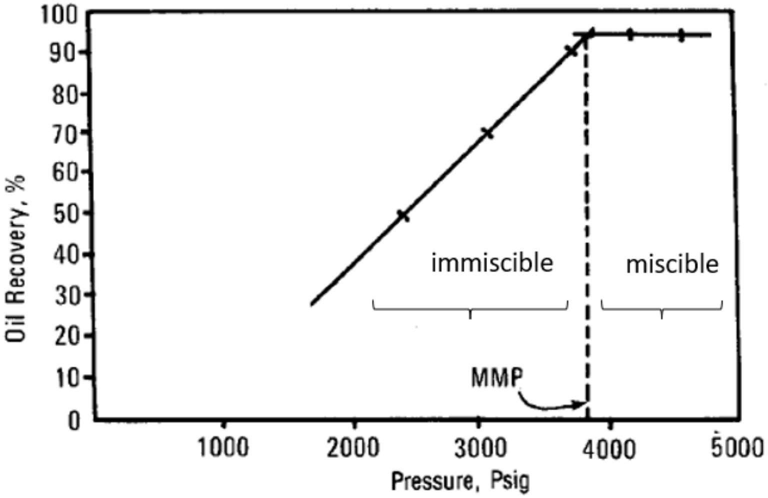
Gas Flooding

- Gas can move upward in the formation away from the wells during the gas injection cycle, while water can move downward in the water cycle. This segregation of fluids will occur when there is a sufficient vertical permeability and density difference between the gas and reservoir fluids. Channeling of gas and water through high-permeability layers usually dominates over gravity tonguing and becomes more significant as heterogeneities increase, permeability and density differences decrease, and fluid velocities become larger.
- If vertical permeability is higher than 200 md, the gravity effect will be dominant and oil recovery will increase.



Miscible and Immiscible Gas Injection

- In miscible gas flooding, gas completely mixes with the crude oil through single or multiple contacts between the gas phase and the crude oil phase. The gas injected reaches miscibility with the crude oil at or above the minimum miscibility pressure (MMP). MMP is the minimum pressure at which crude oil becomes miscible with the injected gas at the reservoir temperature. MMP is a determining factor during miscible gas (e.g. CO_2) flooding, as displacement efficiency is highly dependent on it.
- Immiscible gas flooding entails the injection of gas below the MMP. Below the MMP, there is no miscibility between CO_2 and oil. Technically, immiscible flooding produces about half of the recovery of miscible gas flooding. During immiscible flooding, incremental oil recovery is mainly achieved through oil swelling, which improves the macroscopic displacement efficiency.



Determination of MMP

- The MMP is one of the most important design considerations for a gas flood. There are several proven methods to determine the MMP:

- Slim-tube and multicontact experiments
- Mixing cell methods
- Empirical correlations
- Compositional simulation of slim-tube displacements
- Analytical methods using Equation of State (EOS) and the method of characteristics (MOC)

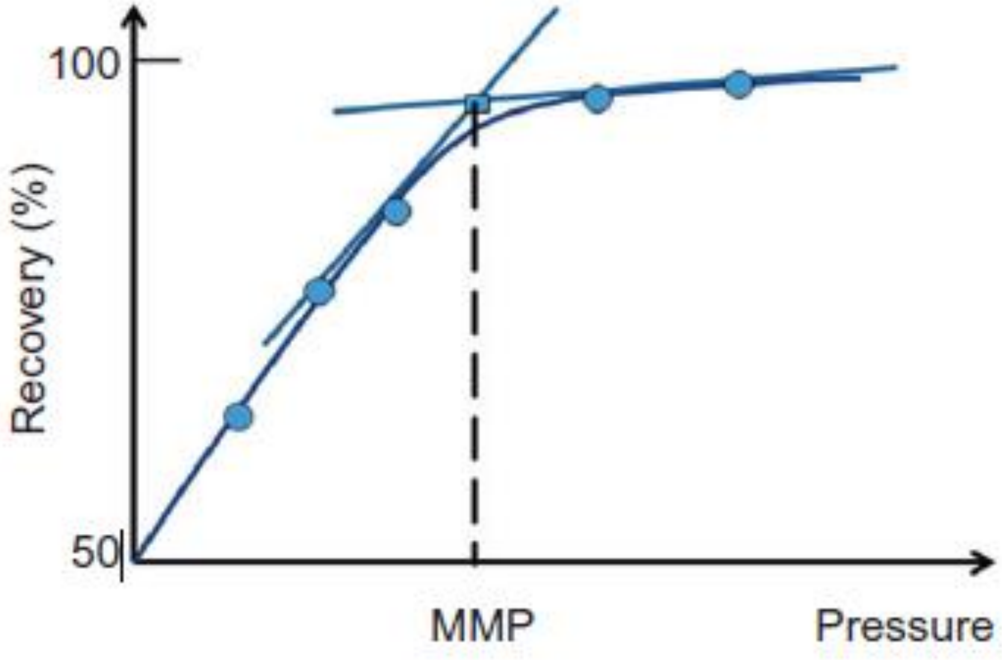
Slim Tube Test

- Slim-tube experiments are very useful to define the minimum pressure for miscibility using crude oil obtained from the field. It is a laboratory test used to estimate the minimum miscibility pressure (MMP). The slim tube consists of a very small internal diameter coiled tube filled with crushed core, sand, or glass bead material. The tube can be quite long, typically between 40- and 60-ft long, to allow miscibility to develop dynamically some distance from the injection point.

- The tube is first saturated with a known volume of oil. The temperature is then fixed at the reservoir temperature. Gas is injected through the tube to displace the oil and the amounts of gas and oil are recorded with time. The recovery is defined as the ratio of the volume of oil produced to the initial oil volume, otherwise known as the pore volumes recovered, a dimensionless number that quantifies the recovery in terms of initial hydrocarbon volume in place.

Determination of MMP

- After minimum miscibility pressure, the oil recovery is no longer increased.



API Gravity vs MMP

- As API gravity increases, required MMP decreases

API	MMP, psia
< 27	4000
27-30	3000
> 30	1200

Minimum Miscibility Pressure

Minimum miscibility pressure:

- The temperature effects on the *MMP* and maximum injection pressure may be estimated by applying the VIT (Vanishing Interfacial Tension) technique. The following correlations could be utilized for determination of *MMP* for cases which the test temperature T is considered as show below;

$MMP = 0.116 * T - 27.1$ for dead oil and pure CO_2 system (1)

$MMP = 0.222 * T - 51.0$ for dead oil and impure CO_2 system (2)

$MMP = 0.168 * T - 42.7$ for live oil and pure CO_2 system (3)

$MMP = 0.194 * T - 42.2$ for live oil and impure CO_2 system (4)

where

MMP = Minimum miscibility pressure, MPa

T = Reservoir temperature, K

Minimum Miscibility Pressure

Minimum miscibility pressure:

- In addition, the maximum injection pressure can be determined by the subsequent equations as follows;

P_{max} =0.384 * T - 102.8 for dead oil and pure CO_2 system (5)

P_{max} = 0.281 * T - 61.9 for dead oil and impure CO_2 system (6)

P_{max} = 0.417 * T - 113.5 for live oil and pure CO_2 system (7)

P_{max} = 0.247 * T - 50.8 for live oil and impure CO_2 system (8)

where

P_{max} = Maximum injection pressure, MPa

T = Reservoir temperature, K

Gas Injection – Class Example

Example: Determine the MMP and maximum injection pressure for the following systems (assume the reservoir temperature is 80 °C):

1. Dead oil and pure CO_2 system
2. Dead oil and impure CO_2 system

Solution: $T = 80 + 273.15 = 353.15$ K

1. Using Eq. (1), *MMP* can be calculated;

$MMP = 0.116 * 353.15 - 27.1 = 13.86$ MPa

and P_{max} can be calculated from Eq. (5);

$P_{max} = 0.384 * 353.15 - 102.8 = 32.80$ MPa

2. Using Eq. (2), *MMP* can be calculated;
$MMP = 0.222 * 353.15 - 51.0 = 27.39$ MPa
and P_{max} can be calculated from Eq. (6);
$P_{max} = 0.281 * 353.15 - 61.9 = 37.33$ MPa

Nitrogen and Flue Gas Flooding

Description

- Increased costs of natural gas and even carbon dioxide have prompted operators to look at other methods to maintain the pressure in petroleum reservoirs. Inert gases are not miscible with many crude oil at low pressures. Also, the API gravity of the crude oil should be 35^o or higher.

- Nitrogen and flue gas are oil recovery methods that use these inexpensive nonhydrocarbon gases to displace oil in systems that may be either miscible or immiscible depending on the pressure and oil composition. Because of their low cost, large volumes of these gases may be injected. Nitrogen and flue gas are also considered for use as chase gases in hydrocarbon-miscible and CO_2 floods.

Nitrogen and Flue Gas Flooding

- The advantages of nitrogen and flue gases include low cost and availability, low compressibility (3 times less compared to carbon dioxide and 1.5 times less compared to methane), which provides significantly lower costs for compression (2-3 times less). Nitrogen has further advantage as it does not corrode, as opposed to flue gases, the metalworks.

- The disadvantages include the low solubility of nitrogen in oil (35-45 m^3/m^3 for light oil and 15-25 m^3/m^3 for heavy oil). The solubility of flue gases is not so different from nitrogen as the gas consists by almost 90% percent of nitrogen. The minimum mixing pressure for nitrogen exceeds 35 MPa, which is significantly higher than for natural gas (25 MPa) and carbon dioxide (8 MPa).

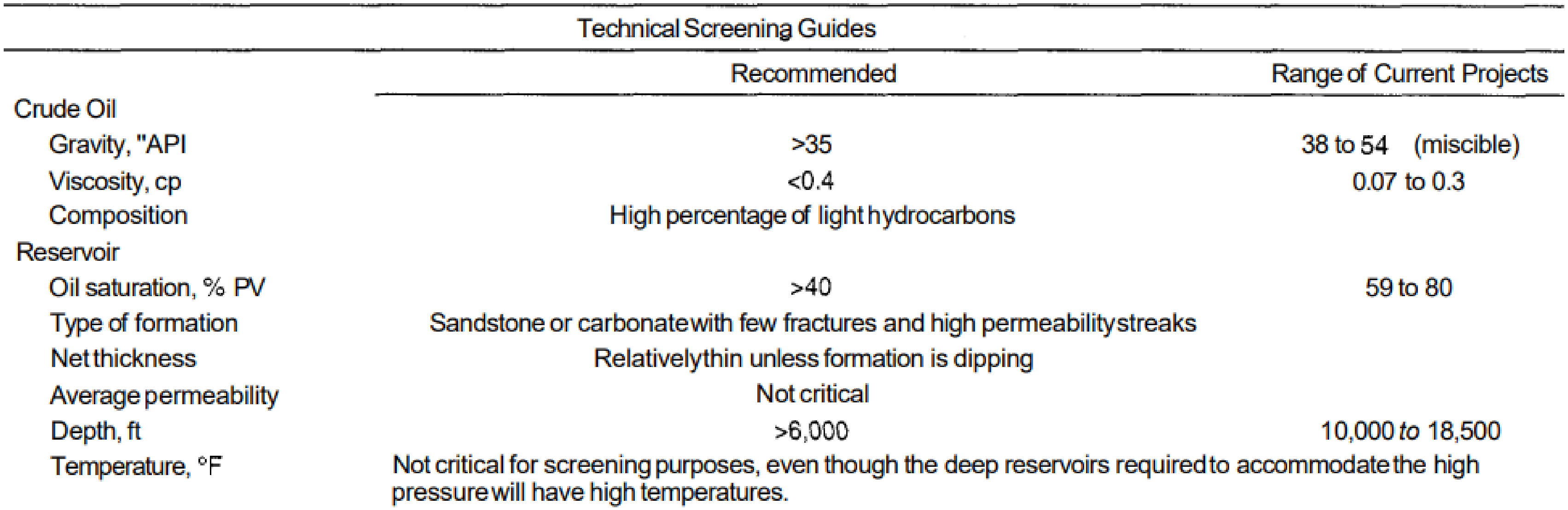
Nitrogen and Flue Gas Flooding

Mechanism

- Nitrogen and flue gas flooding recover oil by (1) vaporizing the lighter components of the crude oil and generating miscibility if the pressure is high enough; (2) providing a gas drive where a significant portion of the reservoir volume is filled with low-cost gases, and (3) enhancing gravity drainage in dipping reservoirs (miscible or immiscible).

Nitrogen and Flue Gas Flooding

Criteria



Technical Screening Guides

	Recommended	Range of Current Projects
Crude Oil		
Gravity, "API	>35	38 to 54 (miscible)
Viscosity, cp	<0.4	0.07 to 0.3
Composition	High percentage of light hydrocarbons	
Reservoir		
Oil saturation, % PV	>40	59 to 80
Type of formation	Sandstone or carbonate with few fractures and high permeability streaks	
Net thickness	Relatively thin unless formation is dipping	
Average permeability	Not critical	
Depth, ft	>6,000	10,000 *to* 18,500
Temperature, °F	Not critical for screening purposes, even though the deep reservoirs required to accommodate the high pressure will have high temperatures.	

Nitrogen and Flue Gas Flooding

Limitations

- Developed miscibility can only be achieved with light oils and at very high pressures; therefore, deep reservoirs are needed. A steeply dipping reservoir is desired to permit gravity stabilization of the displacement, which has an unfavorable mobility ratio. For miscible or immiscible enhanced gravity drainage, a dipping reservoir may be crucial to the success of the project.

Nitrogen and Flue Gas Flooding

Problems

- Viscous fingering results in poor vertical and horizontal sweep efficiency. The nonhydrocarbon gases must be separated from the saleable produced gas. Injection of flue gas has caused corrosion problems in the past. At present, nitrogen is being injected into large successful projects that formerly used flue gas.

Hydrocarbon Injection

Description

- Hydrocarbon-miscible flooding consists of injecting light hydrocarbons through the reservoir to form a miscible flood. Three different methods have been used. The first-contact miscible method uses about 5% PV slug of liquefied petroleum gas (LPG), such as propane, followed by natural gas or gas and water. A second method, called enriched (condensing) gas drive, consists of injecting a 10 to 20% PV slug of natural gas that is enriched with ethane through hexane, followed by lean gas (dry, mostly methane) and possibly water. The enriching components are transferred from the gas to the oil. The third and most common method, called high-pressure (vaporizing) gas drive, consists of injecting lean gas at high pressure to vaporize C2 through C6 components from the crude oil being displaced. A combination of condensing/vaporizing mechanisms also occurs at many reservoir conditions, even though we usually think that one process is dominant.

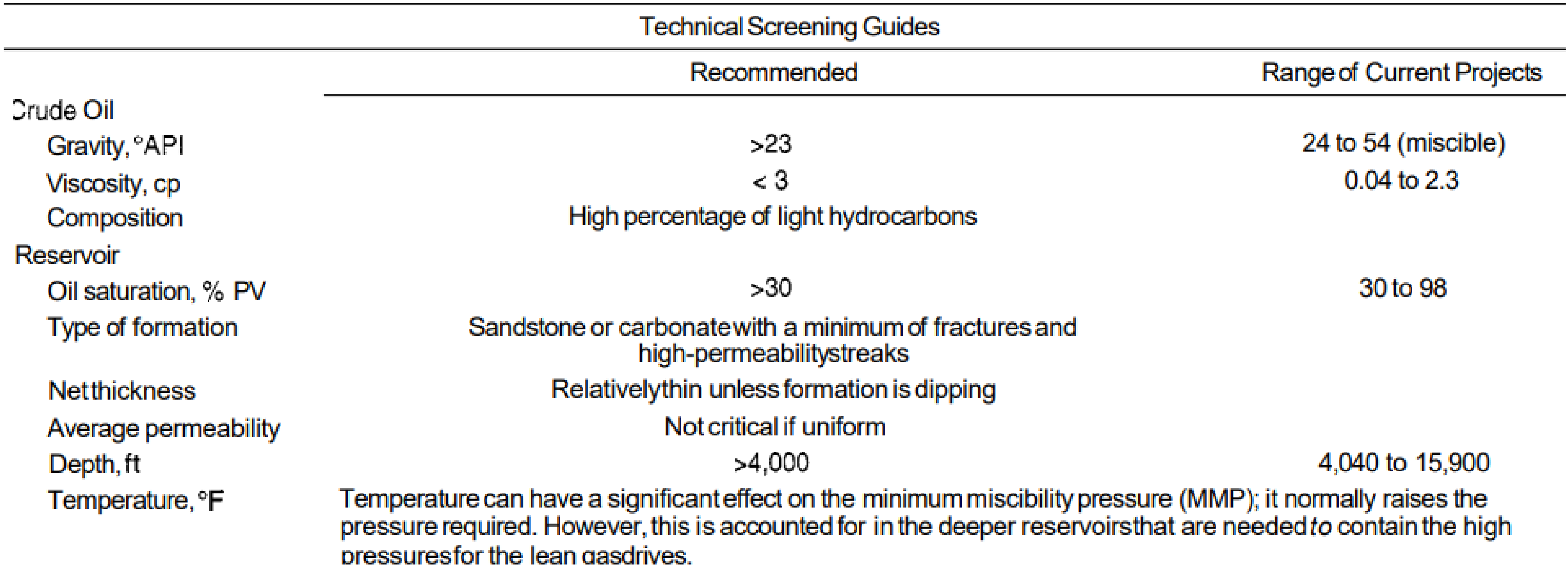
Hydrocarbon Injection

Mechanism

- Hydrocarbon miscible flooding recovers crude oil by (1) generating miscibility (in the condensing and vaporizing gas drive); (2) increasing the oil volume (swelling); (3) decreasing the oil viscosity; and (4) immiscible gas displacement, especially enhanced gravity drainage with the right reservoir conditions.

Hydrocarbon Injection

Criteria



Technical Screening Guides		
	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	>23	24 to 54 (miscible)
Viscosity, cp	< 3	0.04 to 2.3
Composition	High percentage of light hydrocarbons	
Reservoir		
Oil saturation, % PV	>30	30 to 98
Type of formation	Sandstone or carbonate with a minimum of fractures and high-permeability streaks	
Net thickness	Relatively thin unless formation is dipping	
Average permeability	Not critical if uniform	
Depth, ft	>4,000	4,040 to 15,900
Temperature, °F	Temperature can have a significant effect on the minimum miscibility pressure (MMP); it normally raises the pressure required. However, this is accounted for in the deeper reservoirs that are needed *to* contain the high pressures for the lean gas drives.	

Hydrocarbon Injection

Limitations

- The minimum depth is set by the pressure needed to maintain the generated miscibility. The required pressure ranges from about 1,200 psi for the LPG process to 4,000 to 5,000 psi for the high-pressure gas drive, depending on the oil. A steeply dipping formation is very desirable to permit some gravity stabilization of the displacement, which normally has an unfavorable mobility ratio.

Hydrocarbon Injection

Problems

- Viscous fingering results in poor vertical and horizontal sweep efficiency. Large quantities of valuable hydrocarbons are required. Solvent may be trapped and not recovered in the LPG method

CO_2 Injection

Description

- CO_2 flooding is carried out by injecting large quantities of CO_2 (30% or more of the hydrocarbon PV into the reservoir). Although CO_2 is not first-contact miscible with the crude oil, the CO_2 extracts the light-to-intermediate components from the oil and, if the pressure is high enough, develops miscibility to displace the crude oil from the reservoir (MMP). Immiscible displacements are less effective, but they recover oil better than waterflooding.

- It can be performed in miscible or immiscible way. Immiscible CO_2-EOR is less efficient compared to miscible CO_2 -EOR in recovering the residual oil.

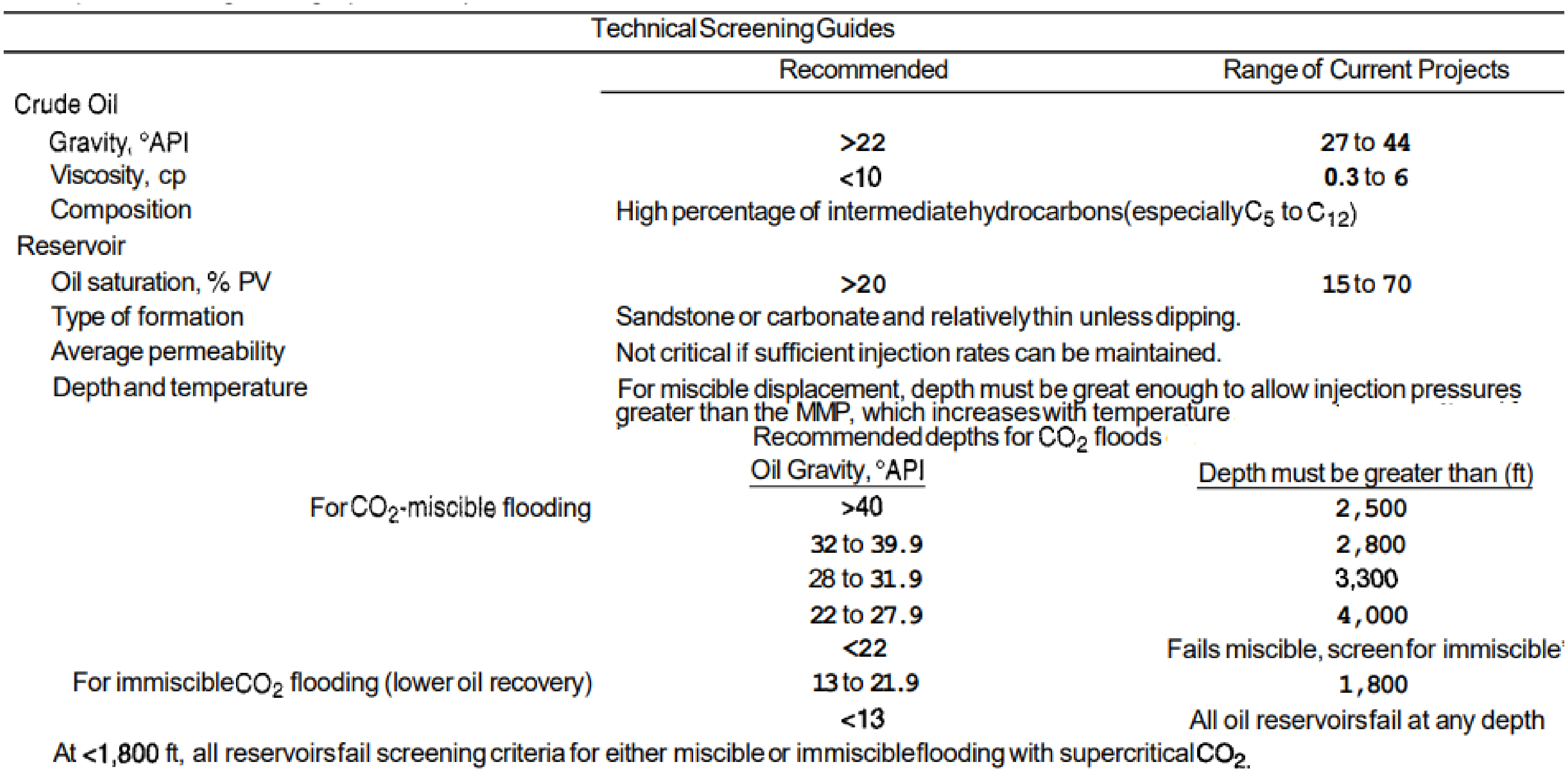
CO_2 Injection

Mechanisms

- CO_2 recovers crude oil by (1) swelling the crude oil (CO_2 is very soluble in high gravity oils); (2) lowering the viscosity of the oil (much more effectively than N_2 or CH_4); (3) lowering the interfacial tension between the oil and the CO_2 /oil phase in the near-miscible regions; and (4) generation of miscibility when pressure is high enough.

CO$_2$ Injection

Criteria



Technical Screening Guides

	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	>22	27 to 44
Viscosity, cp	<10	0.3 to 6
Composition	High percentage of intermediate hydrocarbons (especially C_5 to C_{12})	
Reservoir		
Oil saturation, % PV	>20	15 to 70
Type of formation	Sandstone or carbonate and relatively thin unless dipping.	
Average permeability	Not critical if sufficient injection rates can be maintained.	
Depth and temperature	For miscible displacement, depth must be great enough to allow injection pressures greater than the MMP, which increases with temperature	

Recommended depths for CO$_2$ floods

	Oil Gravity, °API	Depth must be greater than (ft)
For CO$_2$-miscible flooding	>40	2,500
	32 to 39.9	2,800
	28 to 31.9	3,300
	22 to 27.9	4,000
	<22	Fails miscible, screen for immiscible
For immiscible CO$_2$ flooding (lower oil recovery)	13 to 21.9	1,800
	<13	All oil reservoirs fail at any depth

At <1,800 ft, all reservoirs fail screening criteria for either miscible or immiscible flooding with supercritical CO$_2$.

CO_2 Injection

Limitations

- A good source of low-cost CO_2 is required.

Problems

- Corrosion can cause problems, especially if there is early breakthrough of CO_2 in producing wells.

CO_2 Flooding Advantage

- It promotes swelling
- It reduces oil viscosity
- It increases oil density
- It is soluble in water
- It can vaporize and extract portions of the oil
- It achieves miscibility at pressures of only 100 to 300 bar
- It reduces the difference between oil and water density, and then reduce the change for gravity segregation
- It reduces the surface tension of oil and water, and result in a more effective displacement

CO_2 Flooding Disadvantage

- Asphaltene precipitation
- Corrosion problems
- Finding an economical CO_2 source
- The relative low density and viscosity of CO_2 compared to reservoir oil are responsible for gravity tonguing and viscous fingering.

CO_2 Source, Transportation and Recycling

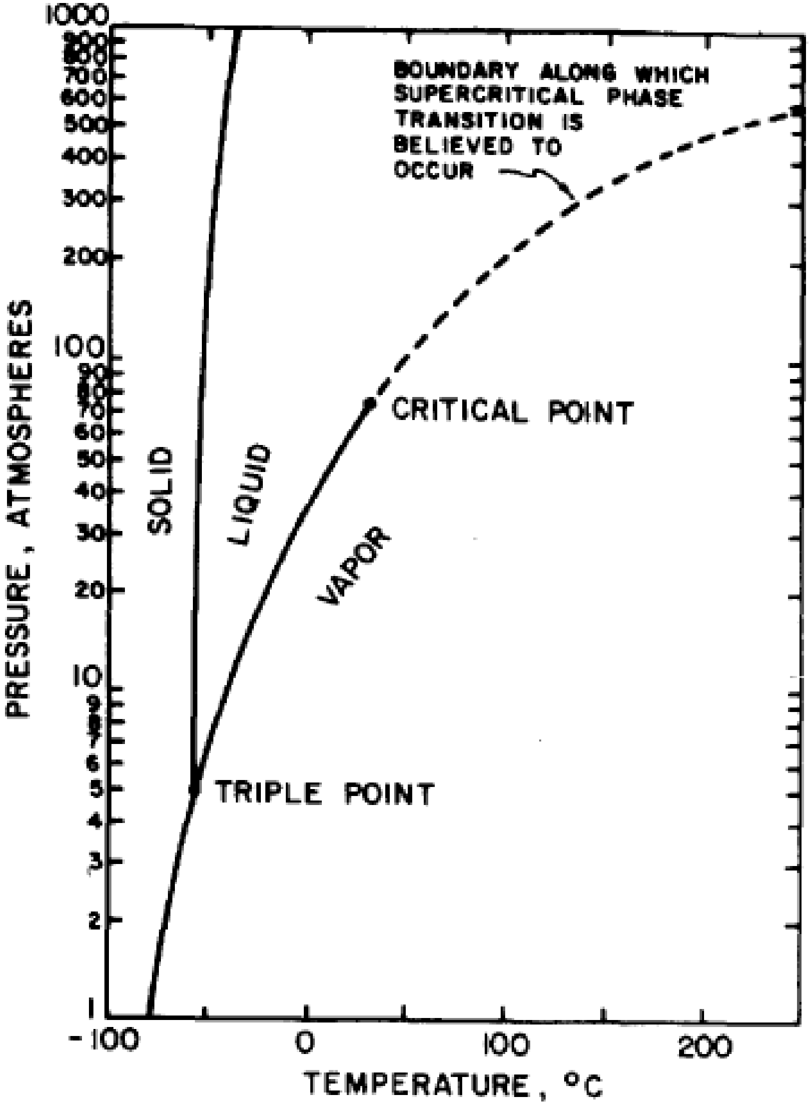
- A reliable source of supply for CO_2 is very important because the gas must be available on a continuous basis in large volumes for long periods of time between 5 to 10 years or more. The CO_2 gas used must have a purity of 90 % or more. If other gases such as methane or nitrogen are present with the CO_2, a higher injection pressure is needed to render the gas miscible with the oil. The best CO_2 sources are naturally occurring high-pressure gas reservoirs with high-purity CO_2, mostly found while exploring for oil and gas. The economics of a CO_2 injection project are improved if CO_2 wells are located in the same geologic basins as those that produce oil, since the CO_2 transportation and injection pressure can then be partially supplied by the CO_2 reservoir pressure. For example, in the US, 25% of the CO_2 injected today for CO_2-EOR is from industrial sources.

- The CO_2 necessary for large long-term projects is transported most economically through a pipeline as vapour at pressures between 1400 to 2000 psi so that two-phase flow does not occur.

- CO_2 recycling is important application to prevent the depletion of CO_2 in the EOR Project. However, about 5% of the CO_2 during injection may be lost due to the leakage and solution in crude oil.

Properties of CO_2

- Carbon dioxide is a colorless, odorless, inert and non-combustible gas. It has a molecular weight of 44.01, which are one and half times higher than that of air.
- The CO_2 is more soluble in oil than in water (2 to 10 times more). Water also is soluble in CO_2 and must be removed by drying to prevent condensation and corrosion in the pipelines.
- In solution with water CO_2 increases water viscosity and forms carbonic acid, which has a beneficial effect on shale rocks (reduction in pH stabilizes) and on calcareous rocks (dissolving effect).



CO_2 Miscible Fick's Law

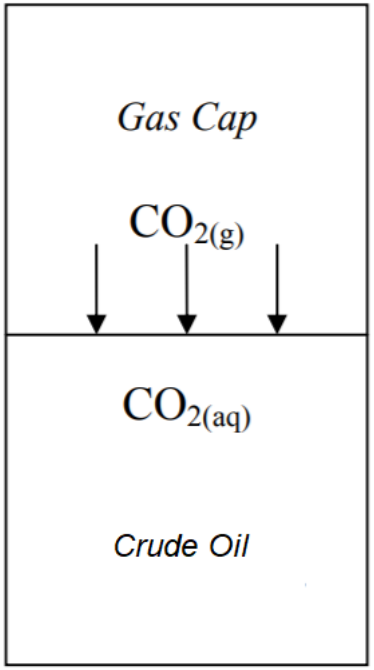
- The convection–diffusion equation can only rarely be solved with a pen and paper (analytically). More often, computers are used to numerically approximate the solution to the equation.

$$D_e \frac{\partial^2 c}{\partial z^2} = \frac{\partial c}{\partial t}$$

(Diffusion dominated -Fick's Law)

$$D_e \frac{\partial^2 c}{\partial z^2} - \frac{u}{\phi}\frac{\partial c}{\partial z} = \frac{\partial c}{\partial t}$$

(Convection dominated)

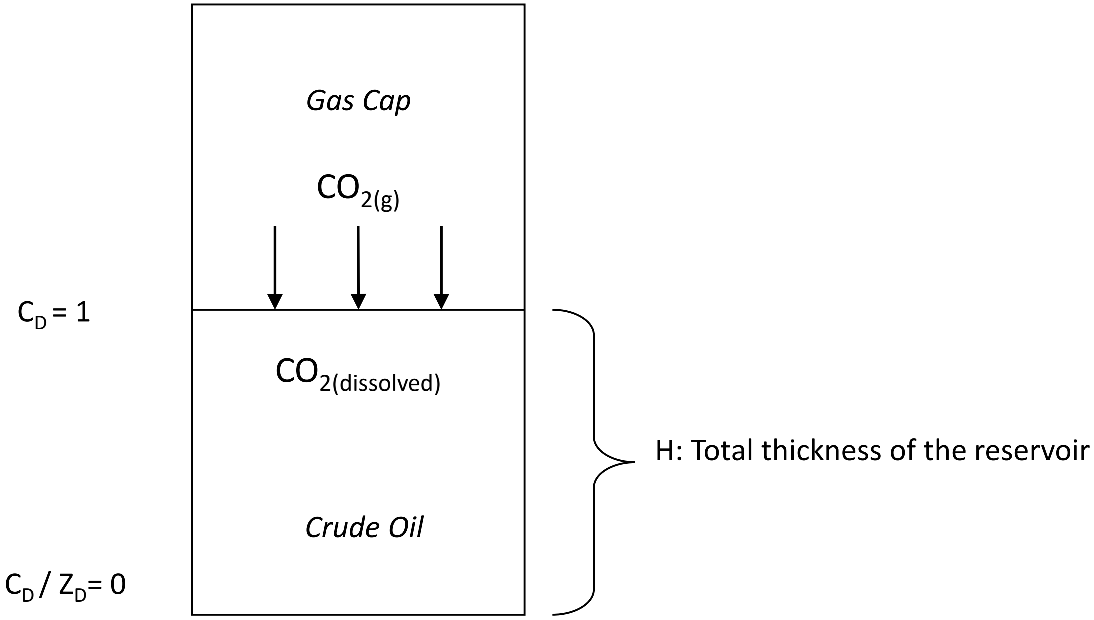


Where,
D_e: Effective diffusion coefficient
c: Concentration
z: Depth
t: Time
u: Velocity
Φ: Porosity

CO_2 Miscible Fick's Law

- Analytical Solutions:

$$\frac{C(z,t)}{C_o} = erfc\left[\frac{z}{2\sqrt{D_e.t}}\right]$$ (Diffusion dominated -Fick's Law)



$$C_D = \frac{C_{CO_2}}{C_{CO_2,sat}}$$

$$Z_D = \frac{z}{H}$$

$$t_D = \frac{u.t}{\phi.H}$$

$$N_{Pe} = \frac{u.H}{\phi.D_e}$$

$$C_D = \frac{1}{2} erfc\left(\frac{z_D - t_D}{2\sqrt{\frac{t_D}{N_{Pe}}}}\right) + \frac{e^{z_D N_{Pe}}}{2} erfc\left(\frac{z_D + t_D}{2\sqrt{\frac{t_D}{N_{Pe}}}}\right)$$ (Convection dominated)

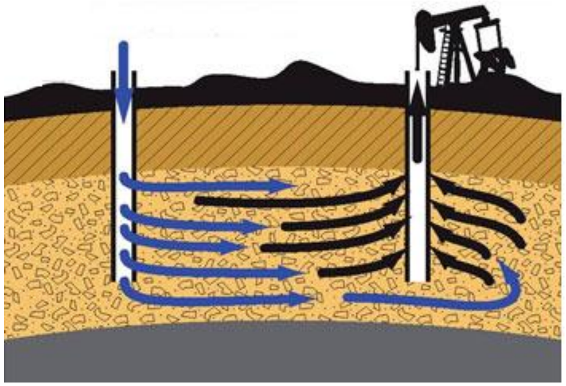
Enhanced Oil Recovery

References:

- Dr. K. Gizem Gül Ertunç, PETE 443 Lecture Notes
- Dr. Ender Okandan, PETE 443 Lecture Notes
- Sheng, J., Enhanced Oil Recovery Field Case Studies, 2013

PNGE 443
Enhanced Oil Recovery

Chapter 7
Chemical Injection Methods



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Chemical Injection Methods

Description

- In chemical EOR (CEOR) techniques, oil is recovered through the injection of chemicals. CEOR is predominantly suitable for heavily depleted and flooded formations (i.e. mature reservoirs).

- Typical chemicals:

- Alkalis
- Surfactants
- Polymers
- Mixtures of chemicals above [i.e; Alkali-Surfactant-Polymer (ASP) flooding, Surfactant-Polymer (SP) flooding]

Enhanced Oil Recovery

Chemical Methods

- Alkali Injection

  - It is the cheapest method among chemical operations, but it has very little application since it has very limited working criteria (acidic oil, sandstone formation, etc.).

- Polymer Injection

  - In the fields where water injection is applied, it is aimed to reduce the viscosity difference between oil and water and to realize an efficient injection operation. By adding the polymer to the water, the viscosity of the water is increased and it is brought closer to that of the crude oil.

- Surfactant Injection

  - It is the most expensive method among chemical operations. It aims for the oil to flow easily by weakening the bonds between oil and water / rock and reducing the interface tension.

Chemical EOR

Field Applications

- CEOR projects implemented in the United States in the 1980s did not show technical and/or economic success. However, in the last decade CEOR successes, specifically polymer flooding, which is the most applied CEOR method worldwide, has been reported in China, along with ASP flooding successfully implemented at pilot and commercial scale in the Daqing, Xinjiang and Shengli oil fields in China. Polymer flooding has also been reported in Canada (East Bodo field), Oman (Marmul field), Suriname (Tambaredjo field) and Mexico (Vacuum field). Other countries that have reported successful applications of ASP flooding are India (Viraj field), Venezuela (Lagomar LVA field) and in the United States (Cambridge Minnelusa field, the West Kiehl and Tanner fields in Wyoming, and Lawrence field in Illinois). Surfactant flooding has been reported in Indonesia (Baturaja formation in the Semoga field), Bahrain (Mauddud field), Texas (Yates field and the Cretaceous Upper Edwards reservoir) and Wyoming (Cottonwood Creek field). Surfactant-polymer flooding has been reported in China (Gudong field). Alkali flooding has been reported in Hungary (H field), India (North Gujarat field), Russia (W field) and the United States (Whittier field in California).

Chemical EOR

Technological Advancements

- Research has led to recent advances in CEOR aiming to improve the economic feasibility of the field application of CEOR processes. Particularly, the development and improvement of effective polymers for EOR is noticeable. Some of these polymers include polyacrylamides (PAM), hydrolysed polyacrylamide (HPAM—the most commonly used polymer), biopolymers (i.e. xanthan gum) and superabsorbent polymer composite (SAPC). Other recent modified polymers are hydrolysed polyacrylamide-acrylamido methyl propane sulfonic acid (HPAM-AMPS) co-polymers, and sulphonated polyacrylamides, which are produced as powders and self-inverting emulsions that are suitable for high temperature applications ranging from 104 to 120°C.

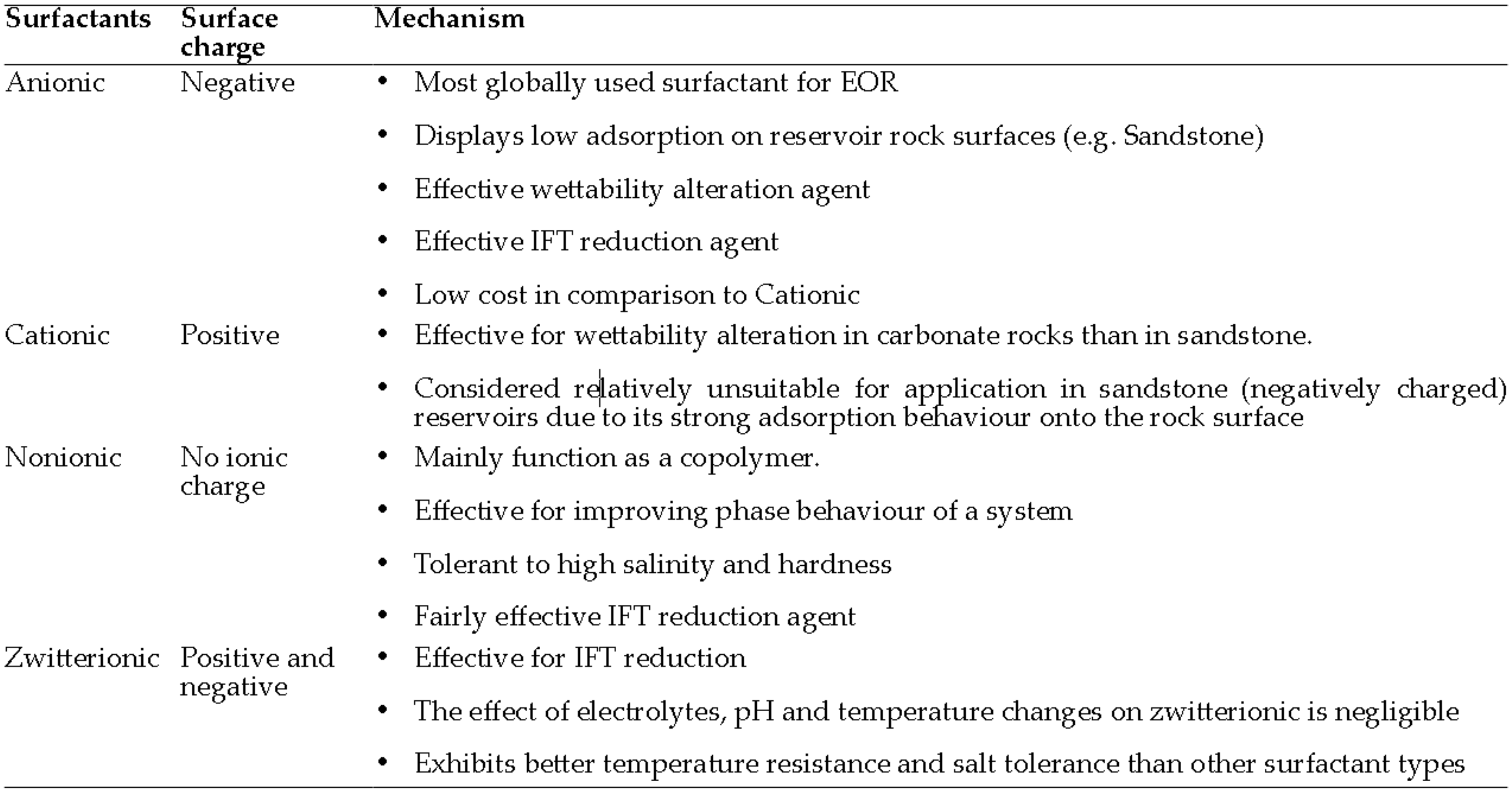
Surfactant Injection

Description

- Surfactants are amphiphilic in nature (hydrophobic and hydrophilic) and are soluble in water and organic solvents. Surfactants effectively reduce the interfacial tension (IFT) between oil and water (i.e. brine). Four basic categories of surfactants exist: anionic, cationic, nonionic and zwitterionic.

Surfactant Injection

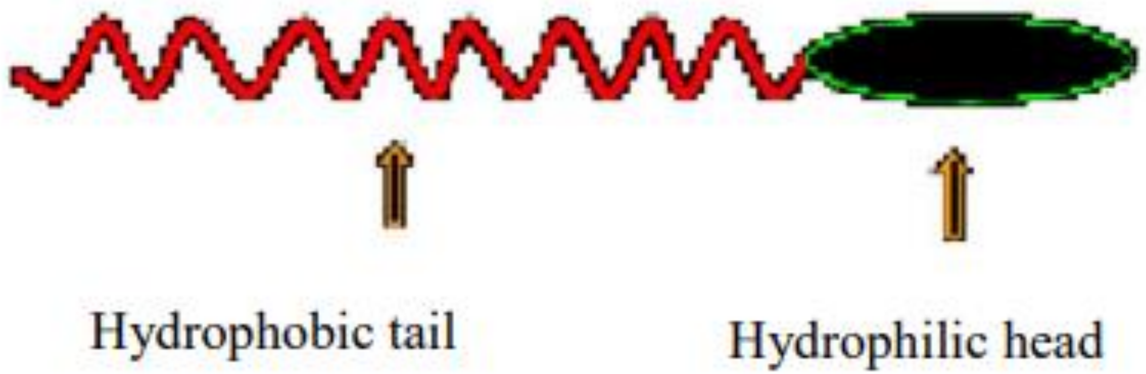
Effective EOR Surfactants



Surfactants	**Surface charge**	**Mechanism**
Anionic	Negative	• Most globally used surfactant for EOR • Displays low adsorption on reservoir rock surfaces (e.g. Sandstone) • Effective wettability alteration agent • Effective IFT reduction agent • Low cost in comparison to Cationic
Cationic	Positive	• Effective for wettability alteration in carbonate rocks than in sandstone. • Considered relatively unsuitable for application in sandstone (negatively charged) reservoirs due to its strong adsorption behaviour onto the rock surface
Nonionic	No ionic charge	• Mainly function as a copolymer. • Effective for improving phase behaviour of a system • Tolerant to high salinity and hardness • Fairly effective IFT reduction agent
Zwitterionic	Positive and negative	• Effective for IFT reduction • The effect of electrolytes, pH and temperature changes on zwitterionic is negligible • Exhibits better temperature resistance and salt tolerance than other surfactant types

Surfactant Injection

Structure of a Surfactant Molecule



Alkaline Injection

Description

- During alkaline flooding, the alkaline solution and organic acids present in the crude oil react to form natural surfactants *in situ*, which cause the reduction of IFT between the brine and oil.

- It is the cheapest method among the chemical operations.

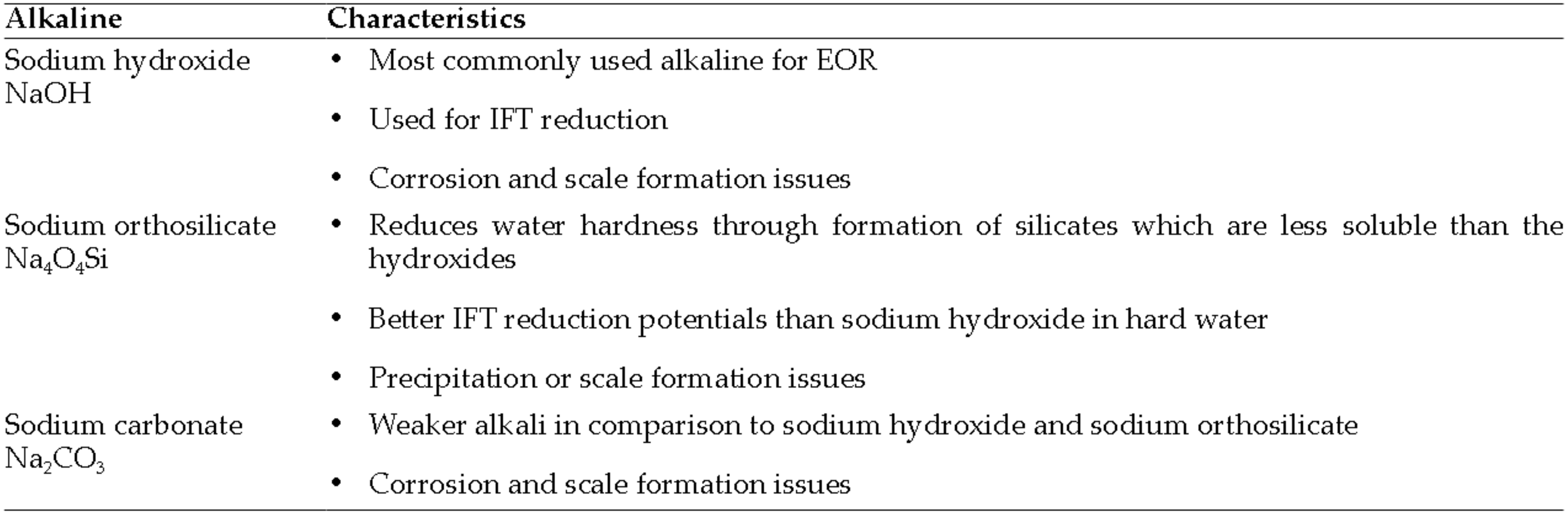
Alkaline Injection

Limitations/Problems

- It has very little application since it has very limited working criteria (acidic oil, sandstone formation, etc.).
- Scale formation is a serious issue during alkaline flooding. Furthermore, the low viscosity of the alkaline solution is associated with the occurrence of unfavourable fingering and poor volumetric sweep efficiency

Alkaline Injection

Effective Alkaline Chemicals for EOR

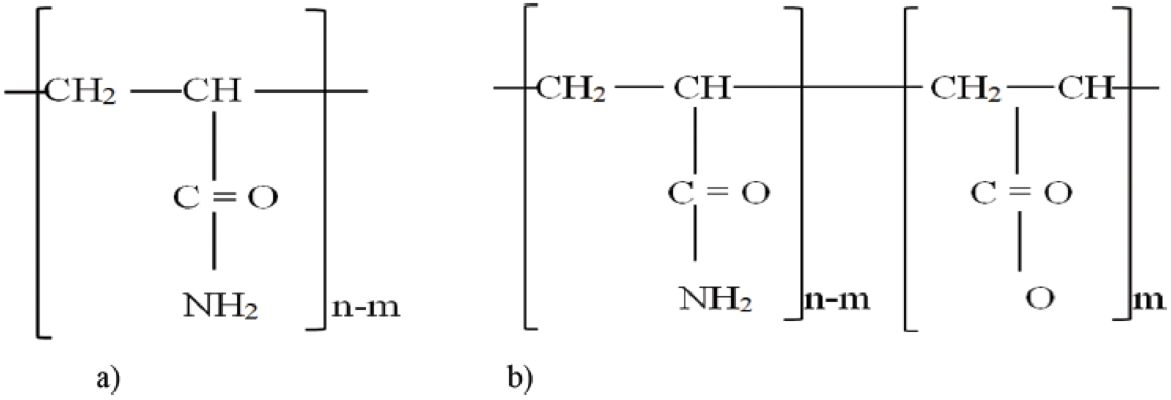


Alkaline	Characteristics
Sodium hydroxide NaOH	• Most commonly used alkaline for EOR • Used for IFT reduction • Corrosion and scale formation issues
Sodium orthosilicate Na_4O_4Si	• Reduces water hardness through formation of silicates which are less soluble than the hydroxides • Better IFT reduction potentials than sodium hydroxide in hard water • Precipitation or scale formation issues
Sodium carbonate Na_2CO_3	• Weaker alkali in comparison to sodium hydroxide and sodium orthosilicate • Corrosion and scale formation issues

Polymer Injection

Description

- For several decades, hydrogel polymers have been used for mobility control. Likewise, polymers in combination with surfactants and alkalis have been applied over the years to improve both the microscopic and macroscopic sweep efficiency. In recent times, several new polymers for EOR have been developed such as synthetic polymers (i.e. polyacrylamide or PAM), hydrolysed polyacrylamide (HPAM), biopolymers (i.e. xanthan gum) an superabsorbent polymer composite (SAPC).



Structure of: (a) polyacrylamide (PAM), and (b) partially hydrolysed polyacrylamide (HPAM)

Polymer Injection

Description

- The objective of polymer flooding is to provide better displacement and volumetric sweep efficiencies during a waterflood. In polymer flooding, certain high-molecular-weight polymers (typically polyacrylamide or xanthan) are dissolved in the injection water to decrease water mobility. Polymer concentrations from 250 to 2,000 mg/L are used; properly sized treatments may require 25 to 60% reservoir PV.

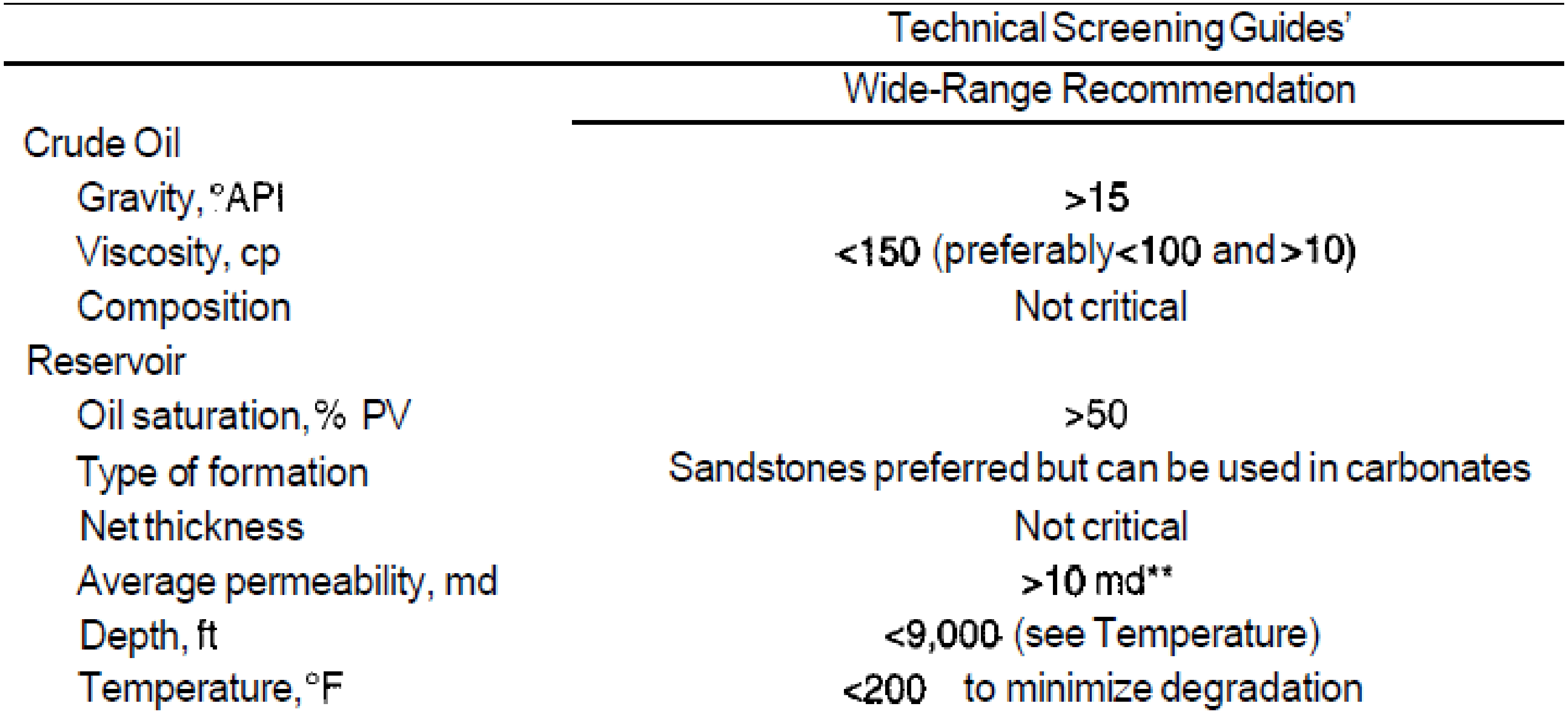
Polymer Injection

Mechanisms

- Polymers improve recovery by (1) increasing the viscosity of water; (2) decreasing the mobility of water; and (3) contacting a larger volume of the reservoir.

Polymer Injection

Criteria



	Technical Screening Guides'
	Wide-Range Recommendation
Crude Oil	
Gravity, °API	>15
Viscosity, cp	<150 (preferably<100 and>10)
Composition	Not critical
Reservoir	
Oil saturation, % PV	>50
Type of formation	Sandstones preferred but can be used in carbonates
Net thickness	Not critical
Average permeability, md	>10 md**
Depth, ft	<9,000 (see Temperature)
Temperature, °F	<200 to minimize degradation

Polymer Injection

Limitations/Problems

- In reservoirs where the rock permeability is less than 50 md, the polymer may sweep only fractures effectively unless the polymer molecular weight is sufficiently low.

Polymer Injection

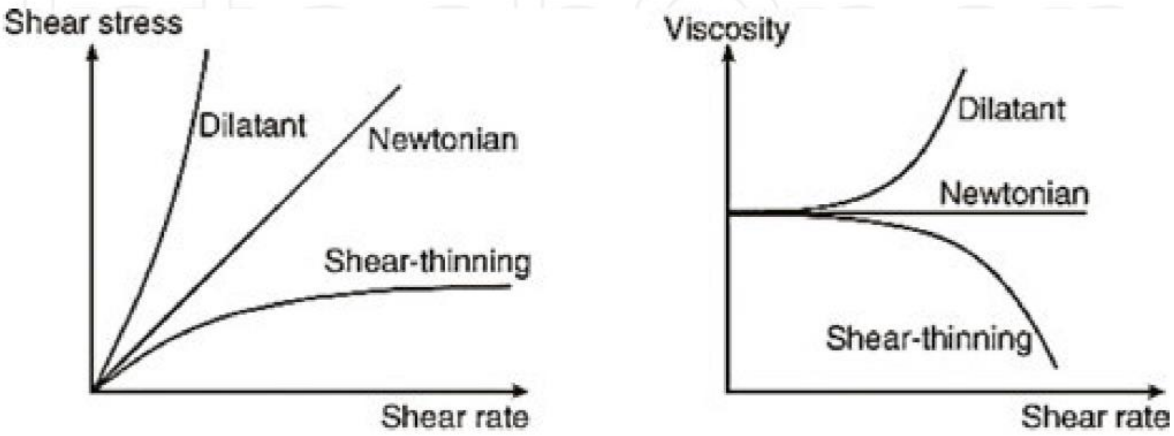
Criteria

- Lithology: sandstone
- Temperature: below 140°C (preferred below 100°C)
- Permeability: above 10 mD
- Oil viscosity: below 10,000 cP
- Current oil saturation: above residual oil saturation or presence of mobile oil
- Salinity of injection water: <200 g/L total dissolved salts.

Polymer Injection

Rheology

- Polymer solutions exhibits viscoelastic properties in porous media. They behave as non-Newtonian fluids meaning that the viscosity is dependent on the applied shear. They show a pseudo-plastic (or shear thinning) behavior: viscosity decreases as shear stress increases following a power-law model.



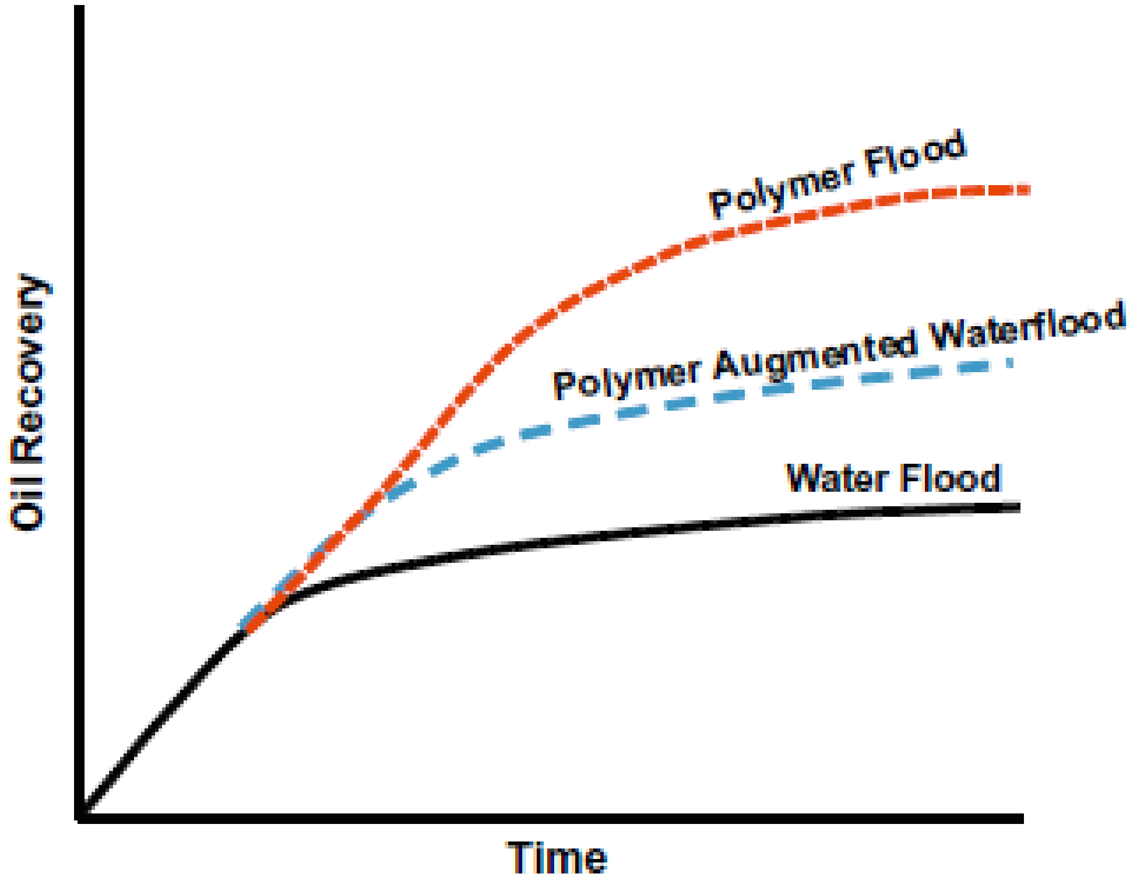
Polymer Injection

Field Cases

- In 2015, there were more than 50 polymer injections running worldwide, excluding the projects still in the design phase or about ready to start in the field. The number of polymer flooding pilot tests and projects has greatly increased in the past years in Europe, some examples are as Bockstedt oil field in Germany, Matzen oil field in Austria operated by the OMV Group, Patos-Marinza oil field (heavy oil reservoir) operated by Bankers Petroleum in Albania. Other polymer flooding pilots in the North Sea, Eastern Europe, Russia, and Kazakhstan; Polymer flooding pilots in Egypt and the Marmul field polymer flooding project in Oman. Also, there are on-going operations in Canada, China and South America.

Polymer Injection

Oil Recovery by Polymer Flood



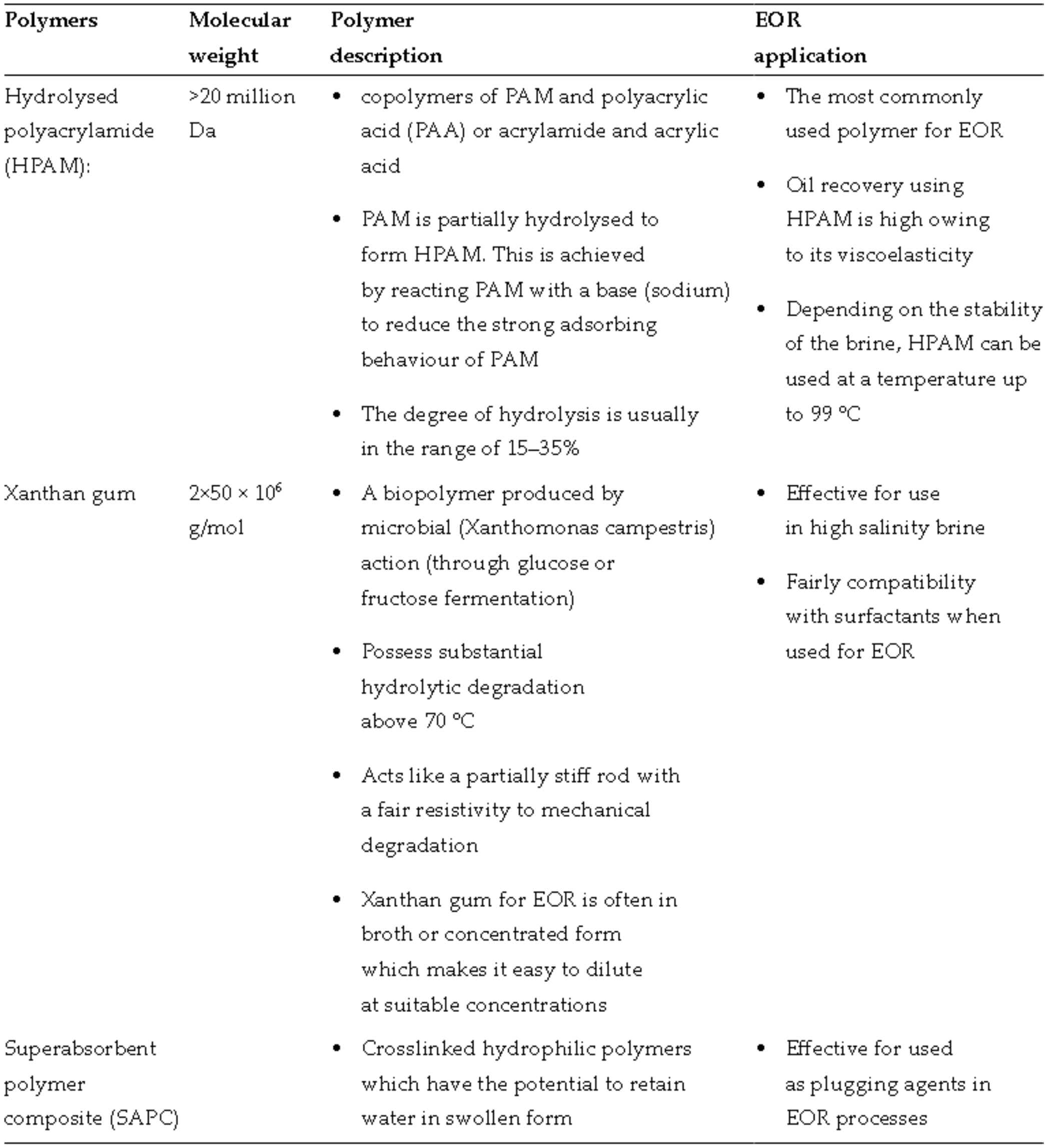
Polymer Injection

Effective Polymers for EOR

Polymers	Molecular weight	Polymer description	EOR application
Hydrogel		• Non-newtonian or pseudo plastic fluids • The fluid viscosity is a function of shear rate	• Used mainly for mobility control • Used in combination with surfactants and alkali for improvement of sweep efficiency
Polyacrylamide (PAM)	>1 × 10^6 g/mol	• First synthetic polymer used for thickening aqueous solutions • The thickening potentials exist in its large molecular weight • >High adsorption capacity on mineral surfaces	• Increases the brine viscosity • Improves EOR performance

Polymer Injection

Effective Polymers for EOR



Polymers	Molecular weight	Polymer description	EOR application
Hydrolysed polyacrylamide (HPAM):	>20 million Da	- copolymers of PAM and polyacrylic acid (PAA) or acrylamide and acrylic acid - PAM is partially hydrolysed to form HPAM. This is achieved by reacting PAM with a base (sodium) to reduce the strong adsorbing behaviour of PAM - The degree of hydrolysis is usually in the range of 15–35%	- The most commonly used polymer for EOR - Oil recovery using HPAM is high owing to its viscoelasticity - Depending on the stability of the brine, HPAM can be used at a temperature up to 99 °C
Xanthan gum	$2{\times}50 \times 10^6$ g/mol	- A biopolymer produced by microbial (Xanthomonas campestris) action (through glucose or fructose fermentation) - Possess substantial hydrolytic degradation above 70 °C - Acts like a partially stiff rod with a fair resistivity to mechanical degradation - Xanthan gum for EOR is often in broth or concentrated form which makes it easy to dilute at suitable concentrations	- Effective for use in high salinity brine - Fairly compatibility with surfactants when used for EOR
Superabsorbent polymer composite (SAPC)		- Crosslinked hydrophilic polymers which have the potential to retain water in swollen form	- Effective for used as plugging agents in EOR processes

Micellar/Polymer, ASP, Alkaline Injection

Description

- Classic micellar/polymer flooding consists of injecting a slug that contains water, surfactant, polymer, electrolyte (salt), sometimes a cosolvent (alcohol), and possibly a hydrocarbon (oil). The size of the slug is often 5 to 15% PV for a high-surfactant-concentration system and 15 to 50% PV for low concentrations. The surfactant slug is followed by polymer-thickened water. The polymer concentration often ranges from 500 to 2,000 mg/L, and the volume of polymer solution injected may be 50% PV or more.

- ASP flooding is similar except that much of the surfactant is replaced by low-cost alkali so the slugs can be much larger but overall cost is lower and polymer is usually incorporated in the larger, dilute slug. For alkaline flooding much of the injection water was treated with low concentrations of the alkaline agent and the surfactants were generated in situ by interaction with oil and rock.

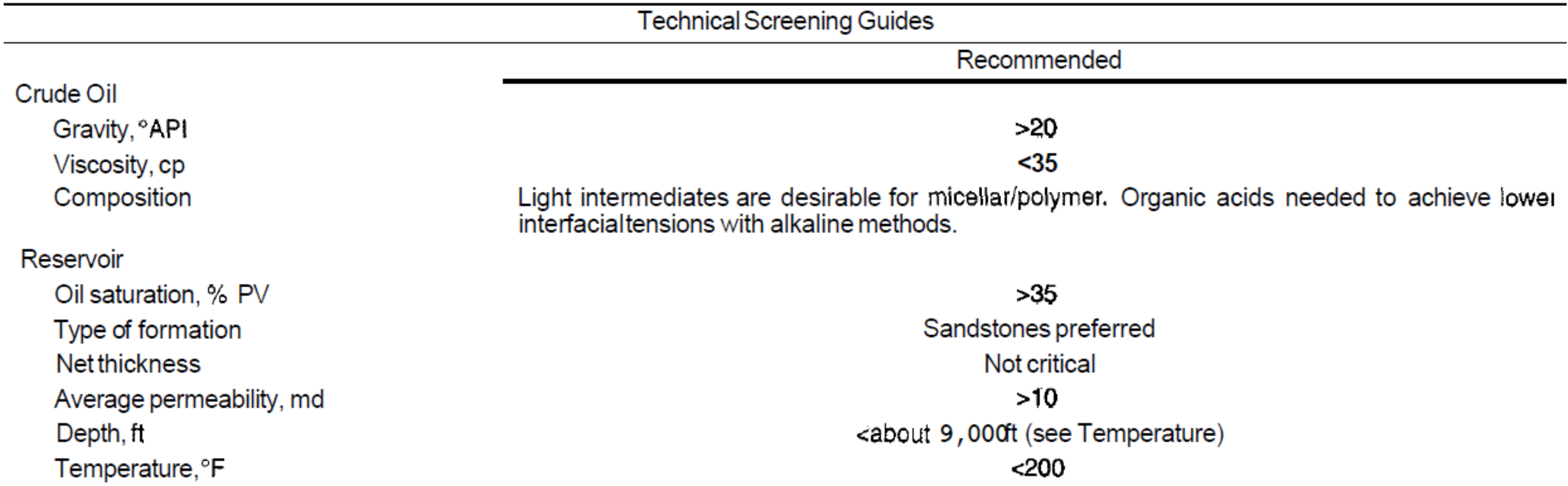
Micellar/Polymer, ASP, Alkaline Injection

Mechanism

- All surfactant and alkaline flooding methods recover oil by **(1)** lowering the interfacial tension between oil and water; **(2)** solubilization of oil in some micellar systems; **(3)** emulsification of oil and water, especially in the alkaline methods; **(4)** wettability alteration (in the alkaline methods); and **(5)** mobility enhancement.

Micellar/Polymer, ASP, Alkaline Injection

Criteria



Technical Screening Guides

	Recommended
Crude Oil	
Gravity, °API	>20
Viscosity, cp	<35
Composition	Light intermediates are desirable for micellar/polymer. Organic acids needed to achieve lower interfacial tensions with alkaline methods.
Reservoir	
Oil saturation, % PV	>35
Type of formation	Sandstones preferred
Net thickness	Not critical
Average permeability, md	>10
Depth, ft	<about 9,000ft (see Temperature)
Temperature, °F	<200

Micellar/Polymer, ASP, Alkaline Injection

Limitations

- An areal sweep of more than 50% on waterflood is desired. Relatively homogeneous formation is preferred. High amounts of anhydrite, gypsum, o clays are undesirable. Available systems provide optimum behavior over a narrow set of conditions. With commercially available surfactants, formation-water chlorides should be <20,000 ppm and divalent ions (Ca++ and Mg++) <500 ppm.

Micellar/Polymer, ASP, Alkaline Injection

Problems

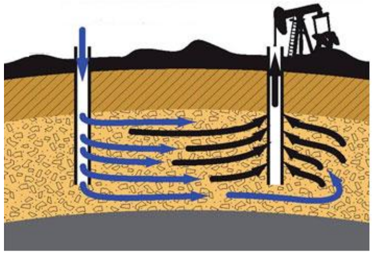
- Complex and expensive systems.
- Possibility of chromatographic separation of chemicals in reservoir.
- High adsorption of surfactant.
- Interactions between surfactant and polymer.
- Degradation of chemicals at high temperature.

References:

- Dr. K. Gizem Gül Ertunç, PETE 443 Lecture Notes
- Romero-Zeron, Chemical Enhanced Oil Recovery, 2016
- Sheng, J., Enhanced Oil Recovery Field Case Studies, 2013

PNGE 443
Enhanced Oil Recovery

Chapter 8
Other EOR Methods
(Microbial Flooding and Smart Water Injection)



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Spring 2020-2021

Microbial Injection

Description

- In MEOR, indigenous or exogenous bacteria can be activated or injected into the reservoir to generate metabolic chemicals that interact with the crude oil and increase oil production. For these applications, bacteria should be small, spherical and less than 20% of the size of the pore throats in the formation. Small cell size (between 0.5 and 5.0 µm) penetrates easily through the reservoir porous medium.

Microbial Injection

Criteria

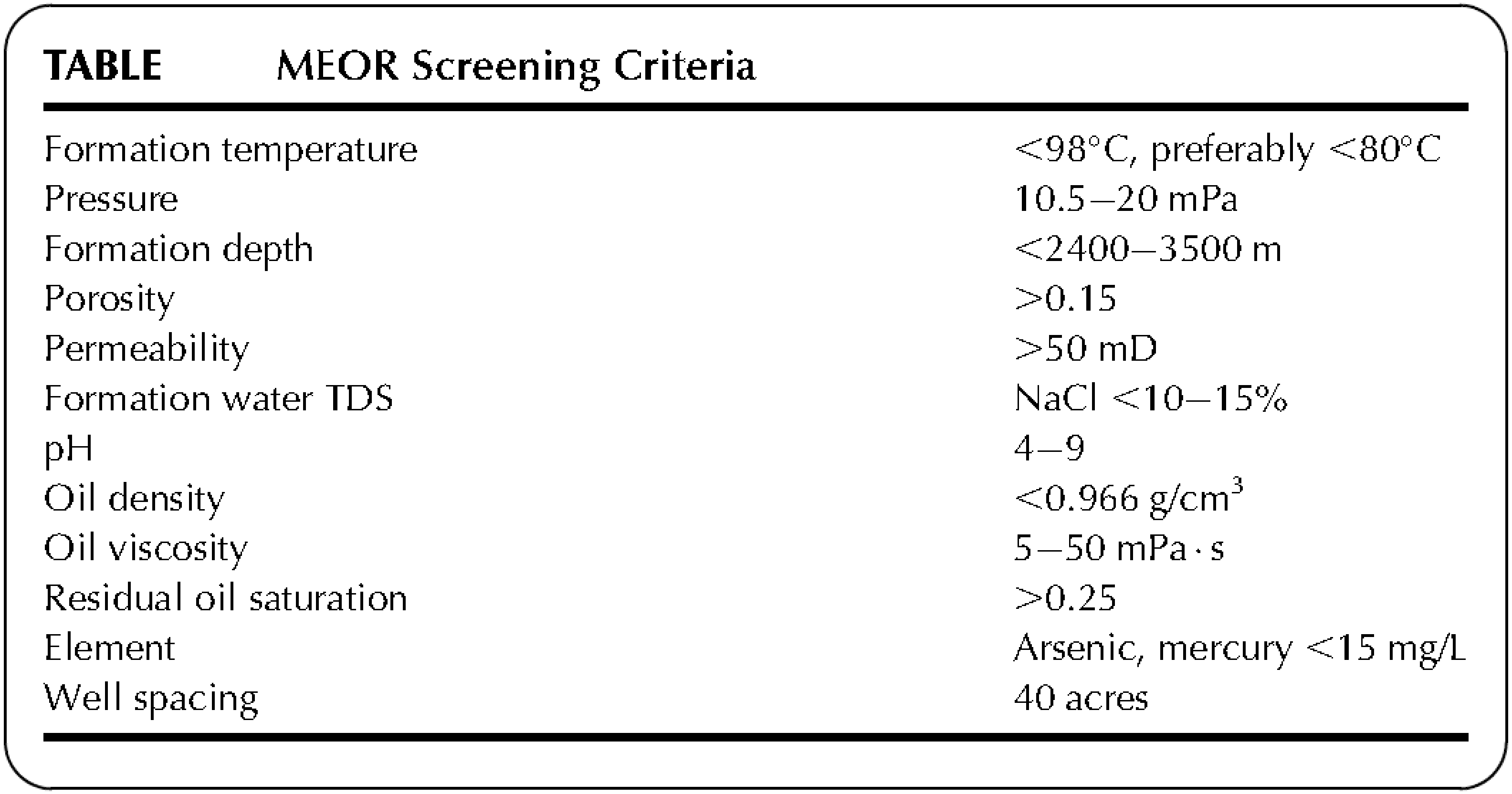


TABLE **MEOR Screening Criteria**

Formation temperature	<98°C, preferably <80°C
Pressure	10.5–20 mPa
Formation depth	<2400–3500 m
Porosity	>0.15
Permeability	>50 mD
Formation water TDS	NaCl <10–15%
pH	4–9
Oil density	<0.966 g/cm^3
Oil viscosity	5–50 mPa · s
Residual oil saturation	>0.25
Element	Arsenic, mercury <15 mg/L
Well spacing	40 acres

Microbial Injection

Process Benefits

- MEOR is environmentally friendly as the MEOR bioproducts are biodegradable, low oil production costs, MEOR is not dependent on oil price like the conventional CEOR processes and MEOR consumes less energy than the TEOR processes. MEOR is economically attractive for application in marginally producing oil fields because the injected bacteria and nutrients are low priced.

Process Limitations

- The MEOR process is complex because it depends on the reservoir chemistry for bacteria functionality and isolation. MEOR renders low incremental oil recovery.

Microbial Injection

History

- The MEOR process was first proposed by Beckmann in 1926, though it was brought to recognition in the 1940s through the work by ZoBell. The first MEOR implementation happened in 1954 in the Lisbon fields in Union County, Louisiana, USA. The acceptance of MEOR as an oil recovery technique found worldwide resistance for decades. One of the reasons was that microbiology was less than 100 years old at the time this EOR technique was proposed. Therefore, the effectiveness of the MEOR process was viewed as a mere curiosity. Prior to the 1940s university laboratories conducted MEOR research. These research efforts continued and eventually led to MEOR growth from extended laboratory work in the 1980s to field level in the 1990s.

Microbial Injection

Mechanisms

- MEOR involves the application of bacteria in oil reservoir for recovery purposes. The bacteria are mostly naturally occurring bacteria in reservoir rocks, hydrocarbon utilising or nonpathogenic. These bacteria produce desired EOR chemicals *in situ* through metabolic reactions, that results from multiple biochemical process steps to generate the EOR chemicals. Nutrients (e.g. fermentable carbohydrates) are injected to provide favourable conditions for microbial metabolism, which results in the production of biosurfactants, biopolymers and gases.

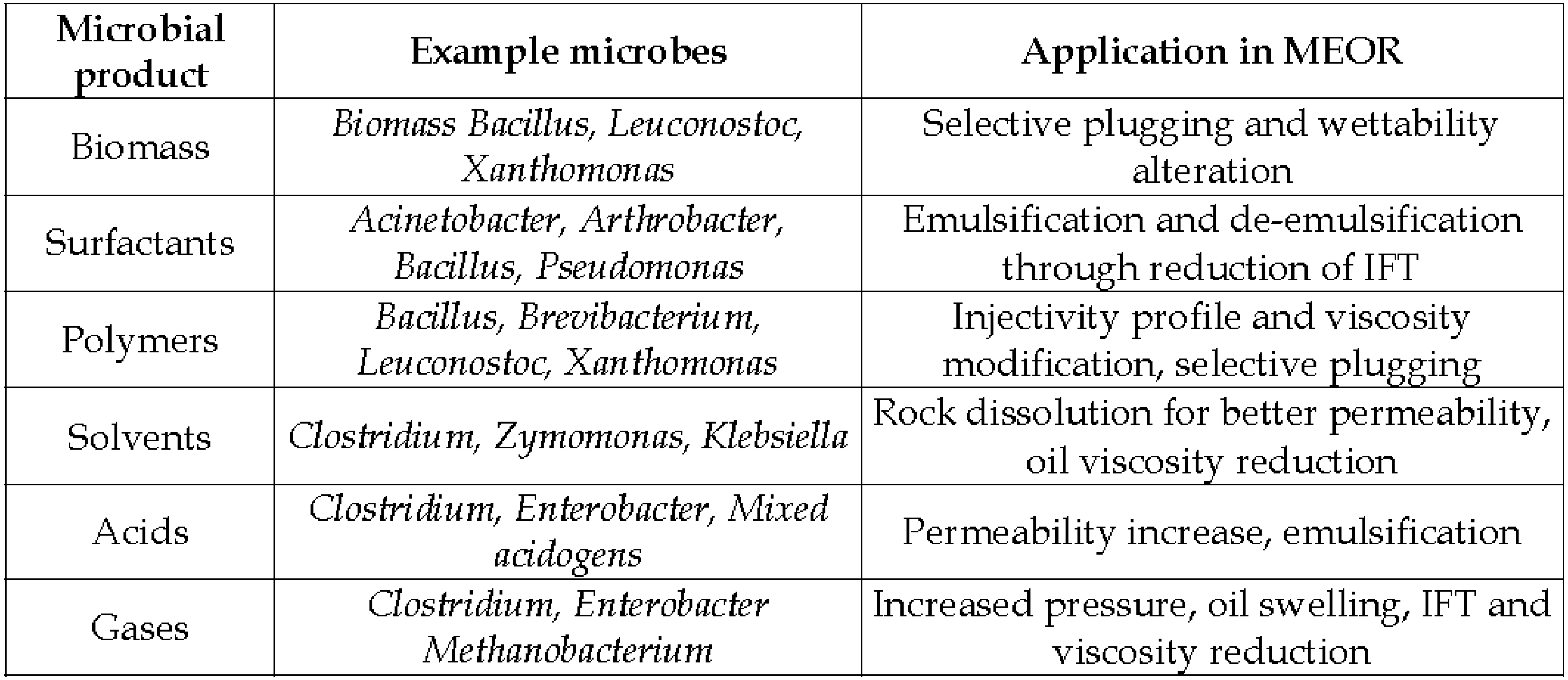
Microbial Injection

Effective Agents for MEOR

MEOR agents (Microbes)	Functionality
Biosurfactants (i.e. Bacillus, Arthrobacter)	• IFT reduction between oil and water • Promotes oil emulsification owing to reduced IFT • Improvement of residual oil displacement • Effective for wettability alteration
Biopolymers (i.e. Bacillus, Xanthomonas)	• Water viscosity can be greatly improved which promotes mobility control • Effective for selective plugging • Used for modifying viscosity of the formation water and injectivity profile
Bacterial consortia (**Biogases:** Clostridium, Enterobacter; **BioSolvents:** Clostridium, Zymomonas; **Bioacids**: Clostridium, Enterobacter)	• Produces gases such as N_2, CH_4, CO_2, and H_2 that are effective in promoting oil viscosity reduction, IFT reduction, and oil swelling • Produces solvents such as alcohols and ketones which dissolves in oil and promotes IFT reduction and oil emulsification • Produces acids that promotes dissolution of clays increasing porosity and permeability
Biomass (i.e. Bacillus, Xanthomonas)	• Effective for selective plugging within the porous media • Effective for altering rock wettability • Effective for the partial degradation of crude oil • Displaces oil through bacterial growth between the oil and the surface of rock and water

Microbial Injection

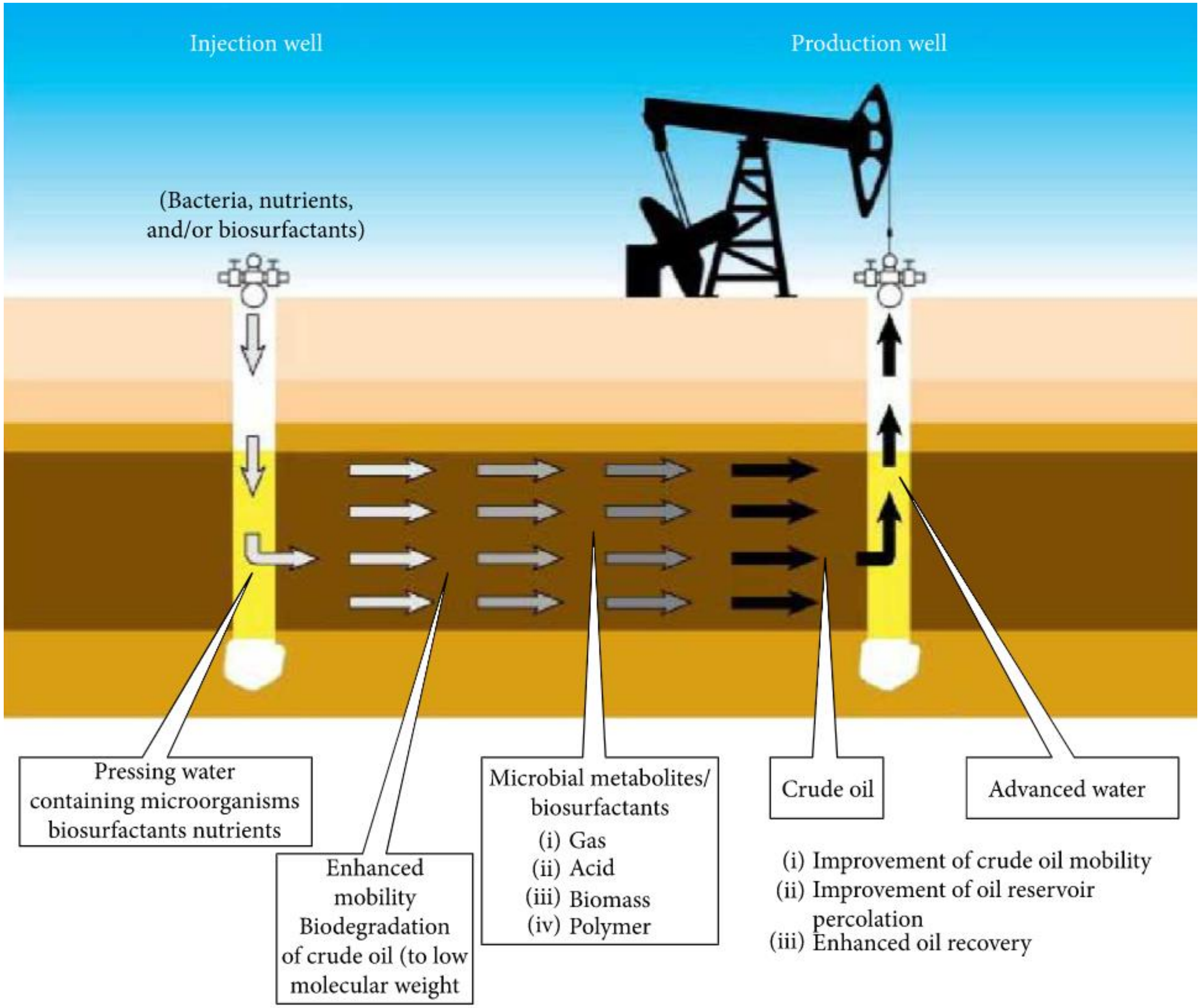
Microorganism, their products and applications in MEOR



Microbial product	Example microbes	Application in MEOR
Biomass	*Biomass Bacillus, Leuconostoc, Xanthomonas*	Selective plugging and wettability alteration
Surfactants	*Acinetobacter, Arthrobacter, Bacillus, Pseudomonas*	Emulsification and de-emulsification through reduction of IFT
Polymers	*Bacillus, Brevibacterium, Leuconostoc, Xanthomonas*	Injectivity profile and viscosity modification, selective plugging
Solvents	*Clostridium, Zymomonas, Klebsiella*	Rock dissolution for better permeability, oil viscosity reduction
Acids	*Clostridium, Enterobacter, Mixed acidogens*	Permeability increase, emulsification
Gases	*Clostridium, Enterobacter Methanobacterium*	Increased pressure, oil swelling, IFT and viscosity reduction

Microbial Injection

MEOR diagram



Microbial Injection

Field Applications

- MEOR field projects have been conducted worldwide in past decades. In Australia, MEOR was applied in the Alton field producing approximately 40% of incremental oil after 1 year of treatment application. In the Asian region, MEOR has also been deployed in China, India and Malaysia. Notable MEOR successes with incremental oil productions ranging up to 204% at field trials have been reported in Argentina, US, Romania, India and Russia. Other MEOR application successes at laboratory and field scale have been reported in Bulgaria, Canada, Former East Germany, Saudi Arabia, the Netherlands, Oman, Romania, Norway and Hungary.

Microbial Injection

Field Applications

- An analysis of the data based on the information gathered from more than 300 MEOR projects, led the evaluation of the technical efficiency and economics of MEOR, which is useful for forecasting treatments outcome in any given reservoir. A collection of significant information from field trials in the USA and Romania was considered as well in the analysis reported.

Microbial Injection

Technological Advancements

- MEOR has developed from laboratory studies between the 1940s and 1980s to successful field applications in the last two decades. Several advances have been made in its application such as the injection of adapted mixed enrichment cultures (AMEC) into reservoirs, the stimulation of indigenous microbiota through the use of salts and oxygen alongside water injection, and the selective plugging of high-permeability channels through the use of ultra-micro-bacteria formed by selective starvation. Recently, the two notable advances in MEOR are genetically engineered micro-organisms EOR (GEMEOR), and the enzyme EOR (EEOR). Both advances involve the growing of microbes that can withstand extreme reservoir conditions using genetic engineering tools and techniques.
- For the microbial injection method, although it has been applied in several fields in the world before, detailed studies on the method are still ongoing, and there is no consensus on the method in the literature yet. The relatively low cost of the method and some positive field applications are promising for the future of the method.

Smart Water (Low Salinity Water) Injection

Description

- EOR by Smart Water is a wettability alteration process towards more water-wet conditions, which induces increased positive capillary forces and increased microscopic sweep efficiency.

- Water flooding has been characterized as a secondary oil recovery process since no specially EOR chemicals were injected. During laboratory studies by many research groups during the last 20 years on wetting properties on different crude oil-brine-rock systems, it has been verified that injected water, which is different in composition compared to the initial formation water, can disturb the established chemical equilibrium of the system. During the process to establish a new chemical equilibrium, the wetting properties will also be changed, which may result in improved oil recovery. If, however, the composition of the injected water is similar to the initial formation water, the chemical equilibrium will be very little affected, only the relative saturations are affected. Thus, we may then say that injection of formation water is a secondary recovery process, but injection of water with a different composition, than the initial formation brine, may change wetting properties and thus acts as a EOR process.

Smart Water (Low Salinity Water) Injection

Description

- Injection of Smart Water can improve oil recovery significantly from both carbonates and sandstones. In order to design an optimized smart water, detailed chemical knowledge about the crude oil-brine-rock interaction is needed and must be obtained from systematic laboratory studies under controlled conditions. The improved chemical understanding of wettability alteration can be used to explain field observations and evaluate possible water-based EOR potential.

- Many geochemical reactions are very slow, which may be negligible during the production time of an oil reservoir. The kinetics of chemical reactions usually increases as the temperature is increased, and therefore, it is not surprising that wettability alteration by water injection may in some cases be sensitive to the reservoir temperature.

Smart Water (Low Salinity Water) Injection

Description

- The validation of “Smart Water” as an EOR fluid has been verified both in the laboratory and in the field by several research groups and oil companies during the last 20 years. Extensive research has been performed in order to understand the chemical/physical mechanism for the wettability alteration process taking place at the rock surface, and the mechanism is still under debate in the published literature.

- Seawater can act as a “Smart Water” to improve the water-wetness of chalk at high temperatures causing enhanced oil recovery by spontaneous imbibition.

Smart Water (Low Salinity Water) Injection

Mechanisms

- The injection of low-salinity water (LSW) to an oil-wet carbonate reservoir has been able to alter its wettability to water-wet. LSW injection causes the dissolution of calcite and an increase in pH due to OH^- ions generated from the dissolution as follows:

$$H_2O + CaCO_3 \leftrightarrow Ca^{2+} + HCO_3^- + OH^-$$

Smart Water (Low Salinity Water) Injection

Mechanisms

- Sulfate can adsorb on the water-wet sites of the chalk surface and reduce the positive charge density. Then, desorption of negatively charged carboxylic material is facilitated. Sulfate is a very strong potential determining ion towards $CaCO_3$(s), and knowing that the concentration of sulfate is about twice the concentration of Ca^{2+} in seawater, it may change the zeta potential of the carbonate surface. Spontaneous imbibition even increased with increased concentration of sulfate. Co-adsorption of Ca^{2+} onto chalk in the presence of sulfate increases the concentration of Ca^{2+} close to the chalk surface, which facilitates a reaction with the carboxylic group. Temperature is also an important parameter. The imbibition rate and oil recovery increases as the temperature increases due to a stronger adsorption of $SO4^{2-}$ and Ca^{2+} onto the chalk surface.

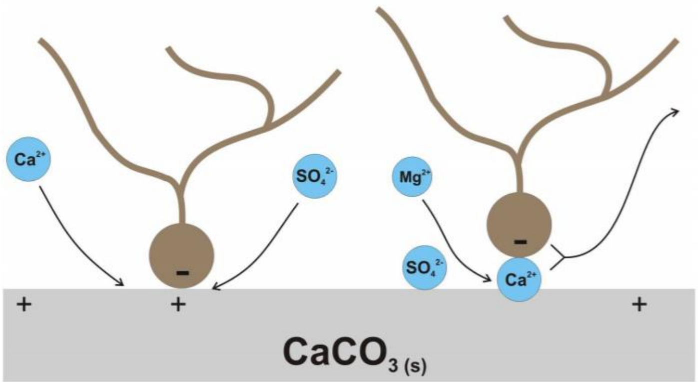


Figure *Schematic model of the suggested mechanism for the wettability alteration induced by seawater. (a) Proposed mechanism when* Ca^{2+} *and* SO_4^{2-} *are the active species. (b) Proposed mechanism when* Mg^{2+}, Ca^{2+} *and* SO_4^{2-} *are the active at higher temperature*

Smart Water (Low Salinity Water) Injection

Wetting in Carbonates

- More that 50% of the known petroleum reserves are trapped in carbonate reservoirs, which can be divided into limestone, chalk, and dolomite. The formation water may be of high salinity, and it is usually rich in Ca^{2+}. On average, the oil recovery from carbonates is well below 30% due to low water wetness, natural fractures, low permeability, and inhomogeneous rock properties.

Wetting in Sandstones

- In contrast to carbonates, a sandstone is composed of many different minerals. Minerals of the silica type are negatively charged at the relevant pH range of the formation water. It is, however, the clay minerals that are most strongly adsorbed by polar components from the crude oil. Clays are chemically unique due to the presence of permanent negative charges, and the clays therefore act as cation exchangers. The relative affinity (replacing power) of cations toward the clay surface is regarded to be:

$$\mathrm{Li^+ < Na^+ < K^+ < Mg^{2+} < Ca^{2+} < H^+}$$

Smart Water (Low Salinity Water) Injection

Wetting in Carbonates

- The filling history of an oil reservoir may also play an important role regarding the wetting properties, especially in carbonates. There are examples of limestone reservoirs that are completely oil-wet even though the crude oil present in the reservoir has a very low acid number. Experimental work showed that it was impossible to obtain wettability modification in this type of rock material using different techniques.

Smart Water (Low Salinity Water) Injection

Wetting in Carbonates

- The carboxylic material in crude oil, as determined by the acid number, AN (mg KOH/g), is the most important wetting parameter for carbonate crude oil-brine-rock systems. Crude oil components containing the carboxyl group,-COOH, are mostly found in the heavy end fraction of crude oils, i.e., in the resin and asphaltene fraction. The bond between the negatively charged carboxylic group,-COO^-, and the positively charged sites on carbonate surface is very strong, and the large molecules will cover the carbonate surface.

- The basic components in the crude oil, quantified by the base number, BN (mg KOH/g), play a minor role as wetting parameter. It was, however, observed that the increase in a basic material improved the water wetness of chalk containing oil with a given AN. It was suggested that an acid-base complex could be formed in the crude oil, which to some extent, made the acidic material less active toward the carbonate surface.

Smart Water (Low Salinity Water) Injection

Factors Affecting Smart Water Injection

- Mineral Surface
- Brine
- Type of Crude Oil
- Temperature
- Wettability
- Injection Brine Concentration
- Connate Water Concentration

Smart Water (Low Salinity Water) Injection

Crude Oil Components Affecting The Wettability

- Research studies have shown that the main crude oil fractions affecting the wettability in porous rock are the asphaltenes and resins,which are rich in polar elements such as nitrogen, sulfur and oxygen (NSO-compounds). It has been experimentally found that a smaller group of components from the asphaltene/resin fractions are more important regarding wettability alteration. These components are polar compounds of acidic and basic nature. Researchers have recognized four different mechanisms for wetting alteration by crude oil. These mechanisms are linked to the asphaltenes content in the oil, acid number, base number and brine composition.

• Polar binding: if no water is present in the porous medium, the adsorption of polar components is likely to happen between polar surface sites and molecules containing polar atoms (NSO-compounds).

• Surface precipitation: Precipitation of asphaltenes occurs when the oil is a poor solvent for the heavy fraction.

• Acid/base interactions: This interaction takes place between sites of opposite electrical charge.

• Ion binding: Divalent or other multivalent ions in the brine are likely to bind to both the mineral surface and the oil/brine interface creating bridges.

Smart Water (Low Salinity Water) Injection

Factors Affecting Smart Water Injection

- *Porous medium*: Sandstones containing clay minerals.
- *Oil*: Must contain polar components (i.e., acids and/or bases).
- *Formation water*: Must be present, and must contain divalent cations, i.e., Ca^{2+} and Mg^{2+}.
- *Low salinity injection fluid:* The salinity is usually between 1000 and 2000 ppm, but effects have been observed up to 5000 ppm. It is appeared to be sensitive to ionic composition (Ca^{2+} vs. Na^{+}).
- *Produced water:* For a nonbuffered system, the pH of the effluent water usually increases about pH 1–3 units, when switching from high salinity to low salinity fluid. It has not been verified that an increase in pH is needed to observe low salinity effects. In some cases, production of fines has been detected, but low salinity effects have also been observed without visible production of fines.
- *Permeability:* Both an increase and a decrease in differential pressure over the core has been observed by switching from high-to-low salinity fluid, which may indicate a change in permeability.
- *Temperature*: There appears to be no temperature limitations to where low salinity effects can be observed. Most of the reported studies have, however, been performed at temperatures below 100°C.

Smart Water (Low Salinity Water) Injection

Environmental Effects

- If produced water is not reinjected into the reservoir, it will be an environmental problem because of the content of aromatic carcinogenic material. The produced water from an offshore carbonate reservoir flooded with SW will contain low concentration of sulfate, even after breakthrough of SW, due to adsorption/precipitation of sulfate in the reservoir. Thus, reinjection of produced water will not be a smart water causing wettability alteration and improved oil recovery. If, however, the produced water is mixed with SW, the good quality of the injected fluid can be maintained.

Smart Water (Low Salinity Water) Injection

Field Applications

- The great success in oil recovery by injection of seawater into the highly fractured, mixed-wet Ekofisk chalk field (North Sea, Norway) is an example of the efficiency of seawater as a smart EOR fluid. Seawater injection has been proven to be a key factor in oil recovery from low-permeable, high porosity and fractured chalk reservoirs in North Sea.

Smart Water (Low Salinity Water) Injection

Overview

- The underlying mechanism for low salinity flooding is not completely understood but it is related to complex crude oil/brine/rock interactions mostly between injected water and rock surface. For wettability alteration, the activation energy or energy barrier for the chemical reactions needed for wettability improvement to take place is crucial. Reservoir temperature plays an important role because activation energy is dependent on the temperature. Higher than 100 °C temperatures have shown to be more efficient at some studies.

Smart Water (Low Salinity Water) Injection

Overview

- It was shown that the ability of a crude oil to alter wettability is dependent on the profile of the crude oil (the API gravity, Acid number and Base number) together with the rock material, i.e.,sandstone vs. carbonate rock.

- Seawater acts as an EOR fluid in Chalk in two ways: (1) As a wettability modifier (smart water) (2) As a pore compaction agent. Due to the high porosity of chalk, compaction may take place during the primary production phase. Substitution of Ca^{2+} by Mg^{2+} at the inter-granular contacts reduces the mechanical strength of chalk. Due to this chemical substitution, the mechanical strength of the chalk may decrease when the cores were flooded with seawater compared to the distilled water or other aqueous solutions free from Mg^{2+} and $SO4^{2-}$ ions.

Smart Water (Low Salinity Water) Injection

Overview

- Laboratory experiments have proven to provide a EOR effect of Smart Water in sandstones , which is explained as a wettability alteration of the rock surface from mixed-wet to more water-wet conditions. This wettability alteration at the rock surface will increase the capillary forces which in turn, increases the microscopic sweep efficiency and overall production of oil.

- Detailed scientific studies are ongoing for smart water injection and there are some successful examples in practice (field scale and lab scale). However, there is no consensus on the method in the literature yet. Some positive field practices regarding the method are promising for the future.

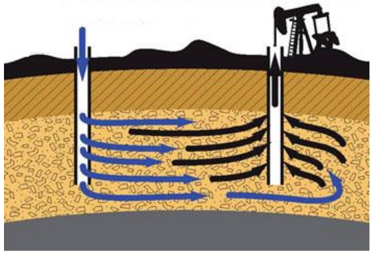
Enhanced Oil Recovery

References:

- Ravari, R., Water-Based EOR in Limestone by Smart Water, 2011
- Sheng, J., Enhanced Oil Recovery Field Case Studies, 2013

PNGE 443
Enhanced Oil Recovery

Chapter 9
EOR History and Activities in Turkey
Evaluation of Oil Fields for EOR in Turkey



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Spring 2020-2021

Upstream Petroleum Sector of Turkey

- 132 Crude Oil Fields (carbonates)
- 75 Natural Gas Fields (sandstones)
- 61,000 bbl/day crude oil production
- 1,1 million m^3/ day natural gas production
- 40 company operating (half of its foreign)
- 20% recovery rate for crude oil fields
- 80% recovery rate for natural gas fields
- 97% water content

Crude Oil Fields World and Turkey Outlook

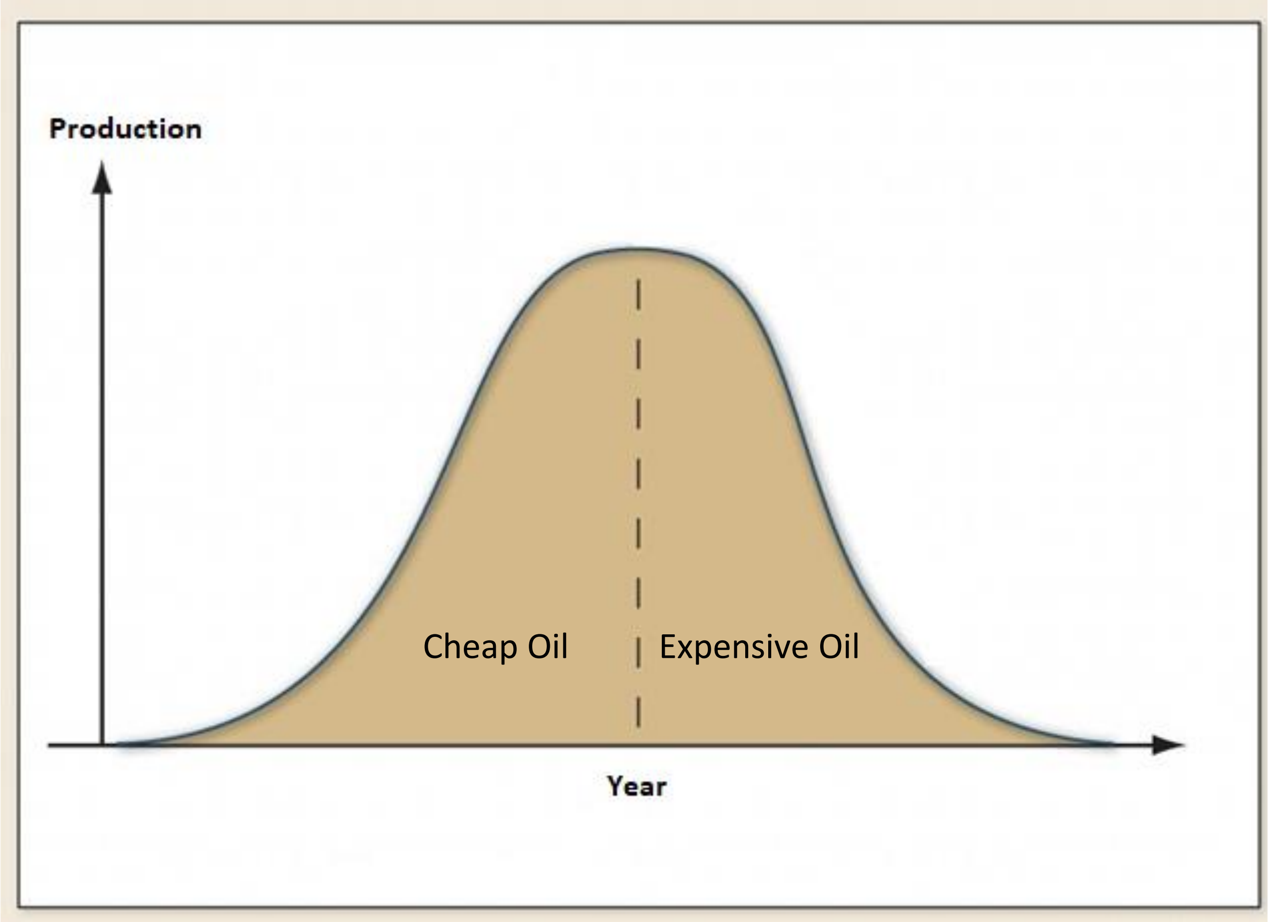
Classification of oil fields discovered in Turkey and World based on Ivanhoe and Leckie's technique

Field Grade	Recoverable Reserve (Million Barrel)	Field Class	World Total	Turkey Total
AAAAA	>50,000	Megagiant	2	-
AAAA	5,000-50,000	Supergiant	40	-
AAA	500-5,000	Giant	328	-
AA	100-500	Major	961	2
A	50-100	Large	895	5
B	25-50	Medium	1109	3
Others	<25	Small-Tiny	37826	122
Total			41161	132

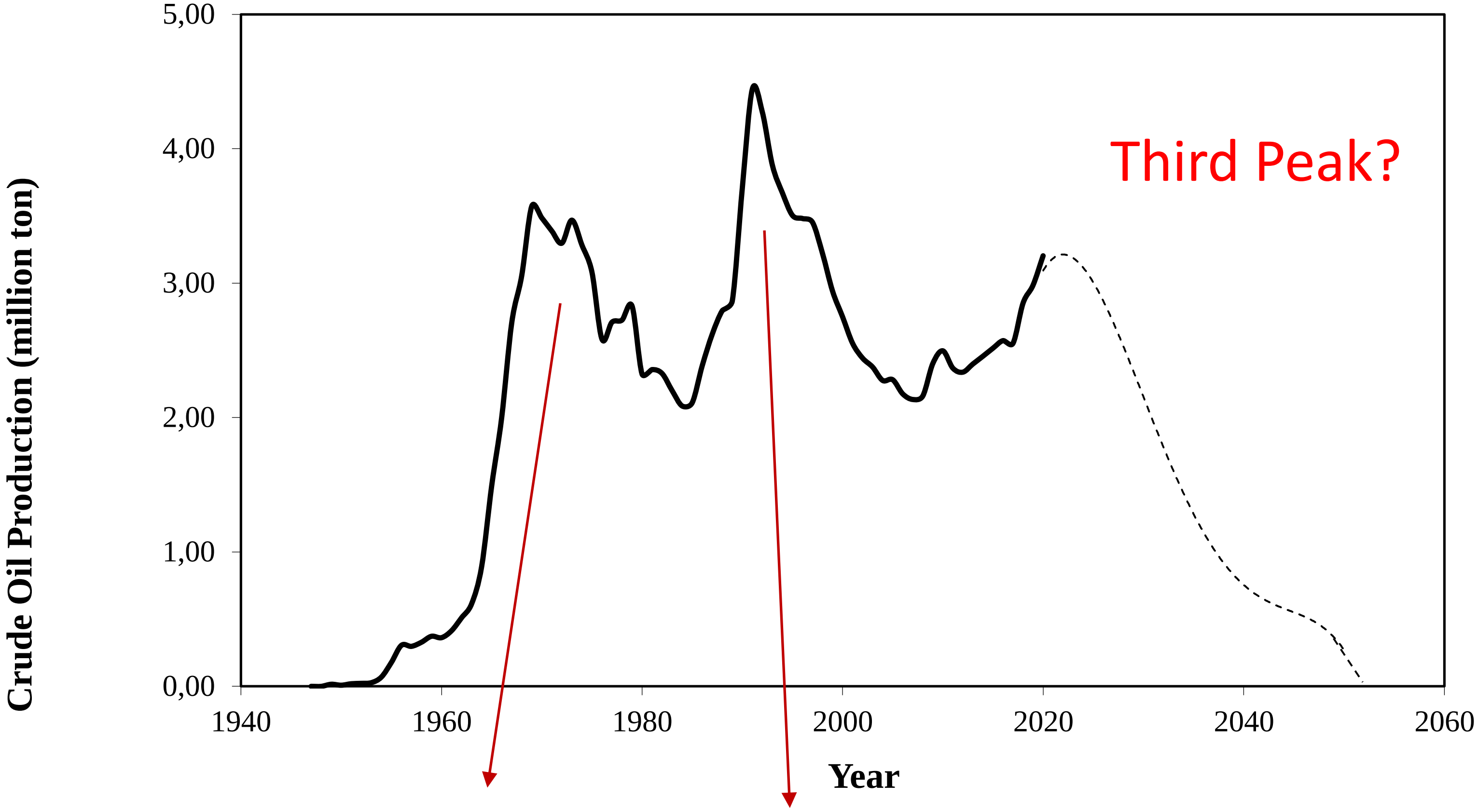
Field Name	Discovery Year	Original Reserve (Million Barrel)	Recoverable Reserve (Million Barrel)	Recovery Factor	API Gravity
Raman	1945	615.3	146.9	23,9	18
Batı Raman	1961	1,841.0	192.9	10,5	13
Kurkan	1963	287.0	67.3	23,4	31
Batı Kayaköy	1964	225.6	63.4	28,1	34
Beykan	1964	432.8	89.8	20,7	33
Şelmo	1964	539.0	99.3	18,4	34
Karakuş	1988	209.1	61.6	29,5	30
Garzan	1951	199.1	46.5	23,4	24
Kayaköy	1961	99.9	31.2	31,2	38
Kuzey Karakuş	1990	87.8	42.2	48,1	29

Hubbert Curve

“The production of natural resources first increases rapidly, after seeing the peak, it decreases dramatically.”



Historical Crude Oil Production of Turkey



-Effect of Batı Raman Field Discovery and other fields

-Effect of EOR on Batı Raman
-Effect of Karakuş and Kuzey Karakuş Discoveries

EOR History in Turkey

EOR Operations in Turkey

City	Field	EOR Method	Operator	Year
Batman	Batı Raman	Immiscible CO_2 Steam Injection	TPAO	1986-continue (CO_2) 1967-1969 (steam) 2012-2013 (steam)
Şırnak	Batı Kozluca	Immiscible CO_2	TPAO	2003-2007
Mardin	Çamurlu	Immiscible CO_2	TPAO	1984-1986
Mardin	İkiztepe	Immiscible CO_2 Steam Injection	TPAO-JNOC	1993-1995
Batman	Garzan	Immiscible CO_2	TPAO	2016-2017
Diyarbakır	Kayaköy	Smart Water Inj.	PERENCO	2018-2019

Çamurlu Field

- Çamurlu field is located in the Southeastern Anatolia Region of Turkey, in the east of Nusaybin district. The field is separated from the İkiztepe field by a fault passing in the west. Natural gas was first discovered in the field in 1975, and low gravity oil was discovered in 1976. Çamurlu CO_2 gas reserve was also discovered in 1976. In 1984, CO_2 injection application was tried on a single well basis for about 3 years, but the desired result was not achieved. The desired CO_2 source was provided from the Muş formation located just below the field. Due to the insufficient surface equipment and the heterogeneous structure of the site, the desired amount of gas could not be injected, and the project was abandoned after a while. Although it is not economical, it has been an important project for TPAO in terms of technique. Details of the CO_2 injection carried out in the field and the operation in Çamurlu-11 and Çamurlu-22 wells are given below:

- Laboratory studies before field application were carried out at the headquarters of TPAO and IFP (French Petroleum Institute).
- \- Both injection and production were made with Çamurlu-11 and Çamurlu-22 wells.
- \- The CO_2 gas considered for injection in the field was obtained from the Muş formation, which is a 2200 meters deep limestone structure located at the deeper point of the same field.

İkiztepe Field

- İkiztepe field is located in the Southeastern Anatolia Region of Turkey, in the province of Mardin. The first discovery was made in 1976 in the field. In the field, with the cooperation of TPAO and the Japanese national oil company (JNOC), studies on CO_2 EOR started in 1987 and started to be implemented a few years later. Details regarding CO_2 operation in the field are given below:

- The operation was first carried out in May 1993.
- Required amount of CO_2 has been supplied from the neighboring field, Çamurlu field.
- 345 MMSCF gas was injected and 18,000 barrels of crude oil was produced.
- The project was stopped due to operational and maintenance (pump, equipment failures, etc.) problems in 1995. But after a while the project was abandoned because it was not economical.

İkiztepe Field

- The steam injection project was also applied in İkiztepe Field between April-1993 and March-1995 by TPAO and JNOC. The Project was stopped because the heat loss due to the fractured carbonate reservoir and the heat losses due to the depth and the heat losses in the surface equipment and well rods made the operation inefficient and difficult to apply. As a result of EOR operation, production increased from 10-20 barrels per day to around 40-50 barrels per day. A total of 82,500 barrels (water equivalent) of steam was injected and 30,500 barrels of crude oil was produced.

Batı Kozluca Field

- The Batı Kozluca field is located in the Southeastern Anatolia Region Nusaybin district and on the Syrian border. The Batı Kozluca field was discovered in 1984 with the Batı Kozluca - 1 well and oil production started in the field in 1985. Due to the presence of CO_2 reserves in the Çamurlu field located 9 km west of the field, it has been evaluated by TPAO that it would be appropriate to carry out the CO_2 EOR operation in the Batı Kozluca field. Details regarding CO_2 operation in the field are given below:

- CO_2 source was provided from the Çamurlu field, which is 9 km away.

- In the project started in 2003, after the injection that lasted until 2007, the production factor of the field has increased from approximately 3% in primary production to over 4%.

- After 2007, the operation continued until 2012 with sequential water - CO_2 injection. However, since the unit was not built for the recovery of carbon dioxide injected in the field, the carbon dioxide that came with the produced oil was given to the air, because of the concern to consume the carbon dioxide gas in the Çamurlu field and because the injected CO_2 came to the production well earlier than expected, gas injection was stopped and normal production was returned. The operation continued with only water injection. Although the production reached 1000 b/d from 500 b/d after the EOR application, it fell back to 500 b/d after the operation was stopped.

Garzan Field

- Since the Dodan - Batı Raman carbon dioxide line passes near the Garzan field, it has been decided to initiate a carbon dioxide injection pilot Project by TPAO, which can be implemented with a low cost investment.
- Re-completion operations were carried out in the wells no. Garzan-34 and Garzan-39 and made ready for carbon dioxide injection. After the wells were prepared for carbon dioxide injection, first injection was started in the well numbered Garzan-34 on 05.09.2016, but the injection was stopped on the same day due to the pressure in the well annulus and the injection was terminated.
- Carbon dioxide injection was carried out as a pilot project in the well numbered Garzan-39 between 07.09.2016 - 26.04.2017. During the injection, the injection well and the surrounding production wells were followed. The injection was terminated when gas came to the surface due to a casing problem in the wells of Garzan-63 and Garzan-36 near the well numbered Garzan-39.
- As a result, after the evaluations made in the Garzan carbon dioxide injection application, which was initiated as a pilot project, no oil production increase or pressure change in the surrounding wells was observed.

Kayaköy Field

- Smart Water Injection operation was operated by private oil company PERENCO first time in Turkey.
- Small and isolated north block, which has 1 producer and 1 injector (Kayaköy-25 and Kayaköy-4 wells) was selected as pilot area.
- Optimum injection and production rate was determined as 750 bpd. Breakthrough was expected within 2 months. This gave sufficient retention time to smart water.
- Laboratory studies were performed at Netherlands.
- Oil production increase due to EOR operation could not be detected.

Batı Raman Field

- The Batı Raman field is located approximately 10 km southeast of Batman province. Oil production in the field, which was discovered in 1961, is made from the Garzan formation. Garzan formation is lithologically composed of limestone. It is the largest crude oil production field of Turkey in terms of reserves. The field, whose production continues for more than half a century, is on the list of important fields in the world. The heavy oil of the field makes it difficult to produce. The reservoir structure of the field with 12° API oil gravity keeps the production factor low (around 10%) despite EOR methods. Approximately 1.7% of the oil in the reservoir was produced due to the initial rock and liquid expansion. Steam injection, air injection and water injection methods have been tried to increase the decreasing production, but none of them have been effective due to the fractured structure of the reservoir and economic reasons. In 1986, immiscible CO_2 EOR operation was implemented, with CO_2 gas supplied by a pipeline from the Dodan field, 90 km away from the Batı Raman field, and positive results were obtained. Thanks to the recycling units established in 1991, a certain amount of the injected gas can be injected back into the field. More than 350 billion scf gas was injected and more than 82 million barrels of extra crude oil was produced.

Batı Raman Field

- The casing pipe collapse and heat loss problems experienced after the steam injection applications in the Batı Raman field stopped the operations. Compared to other steam injection applications (shallow sandstone reservoirs) in the world, Batı Raman (relatively deep carbonate reservoirs) steam injection is considered an inefficient operation. The highly fractured and heterogeneous nature of the Batı Raman field prevented the injection of steam as desired, thus affecting the distribution of the heat in a balanced way and made the operation inefficient. In addition, injection of the relatively deep formation has affected the efficiency of the operation as it increases the amount of heat loss. In order to prevent heat loss, insulating rods must be placed. The application has been a research project rather than an economic project. A total of 400,000 barrels (water equivalent) of steam was injected and 60,000 barrels of crude oil was produced at the last steam project. 55,000 barrels of crude oil was consumed to create steam.

CO_2 Fields

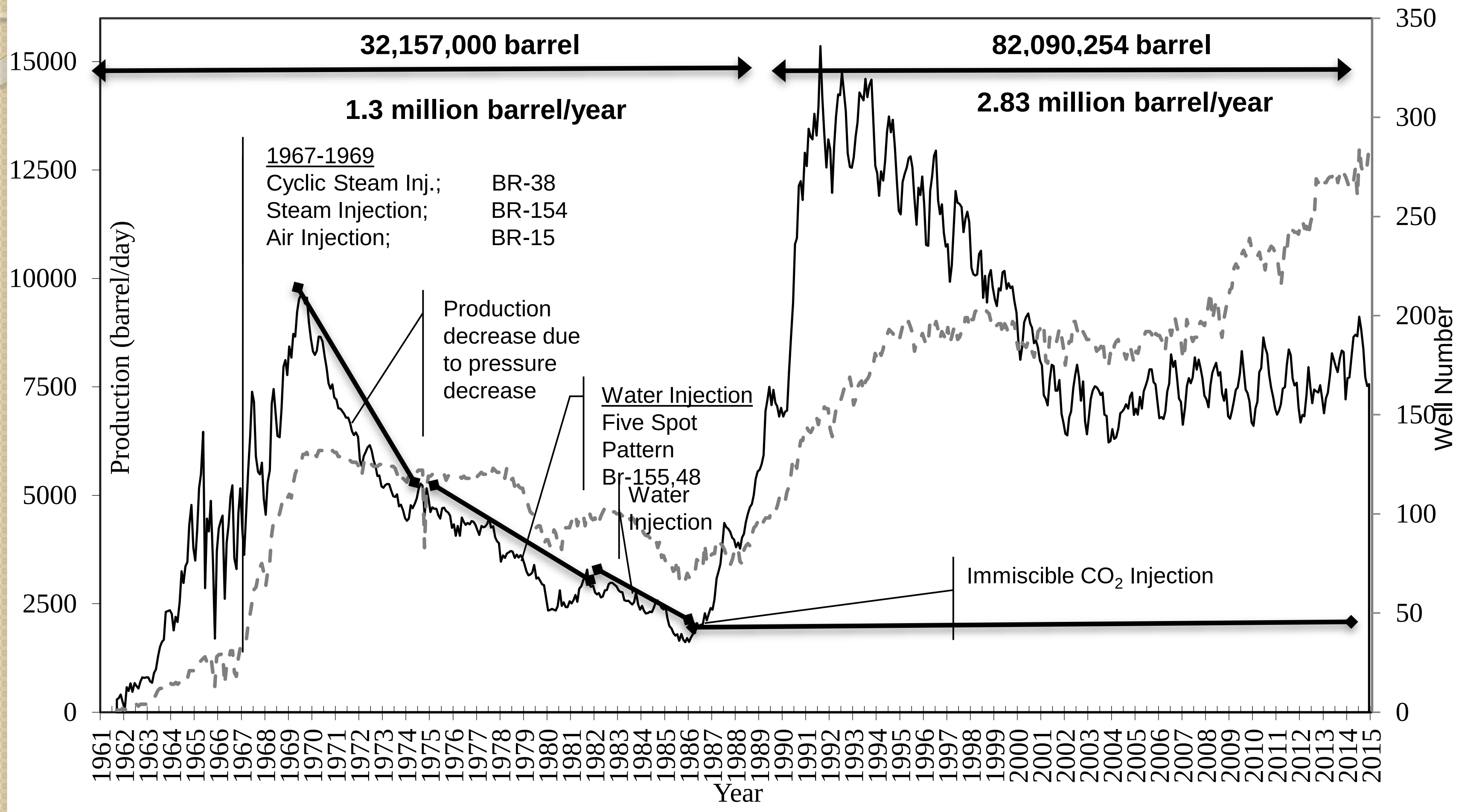
- Dodan and Çamurlu CO_2 fields in Turkey are important sources for EOR applications. The location of these fields in the Southeastern Anatolia Region provides an important advantage for CO_2 injection due to its distance to oil fields. CO_2 from the Dodan Field is used in Batı Raman Production field; CO_2 gas in Çamurlu Field was previously used for EOR production at Batı Kozluca, Çamurlu and İkiztepe Production fields.

CO_2 Fields

City	Field	CO_2 ratio (mol,%)	Ø	k (md)	Depth (m)	T (°C)	Spe. Gra.	μ (cp)
Mardin	Çamurlu	73.37	20	40	1450	46	1.306	0.0164
Siirt	Dodan (Garzan)	89.66	5	10	1800	68	1.270	0.0410
Siirt	Dodan (Mardin)	90.46	3	20	2050	74	1.406	0.0440

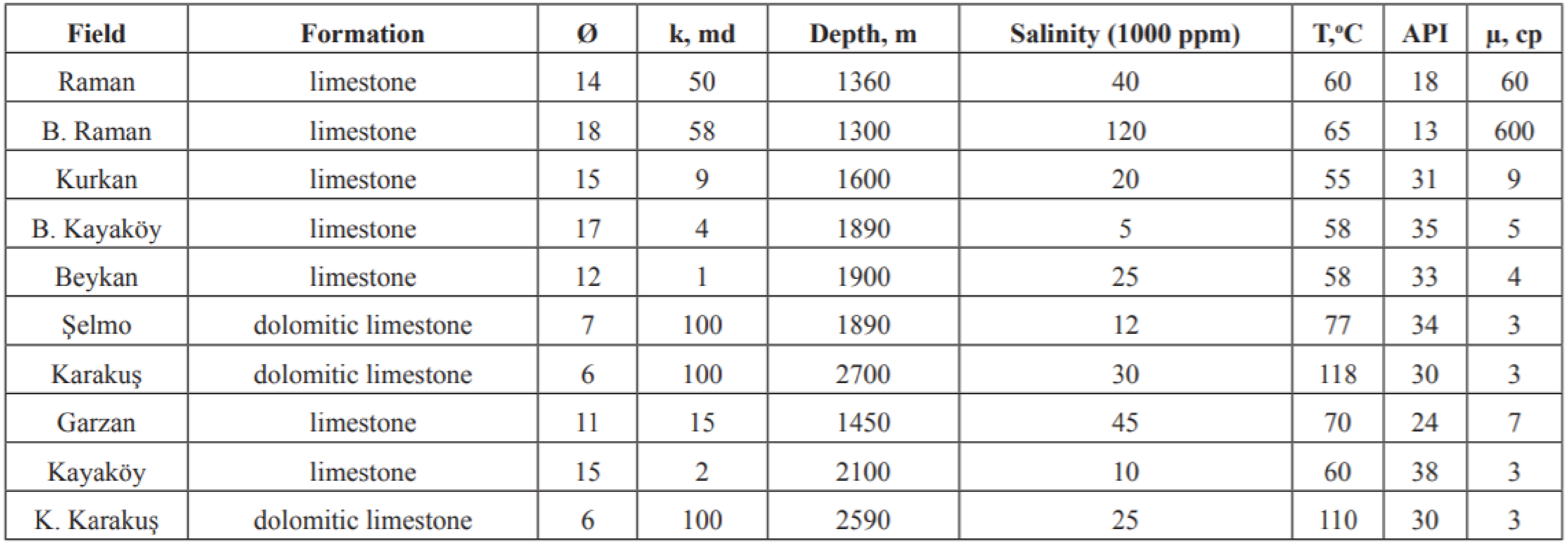
Active EOR Operation in Turkey

"An example of the EOR method in Turkey: Batı Raman Field"



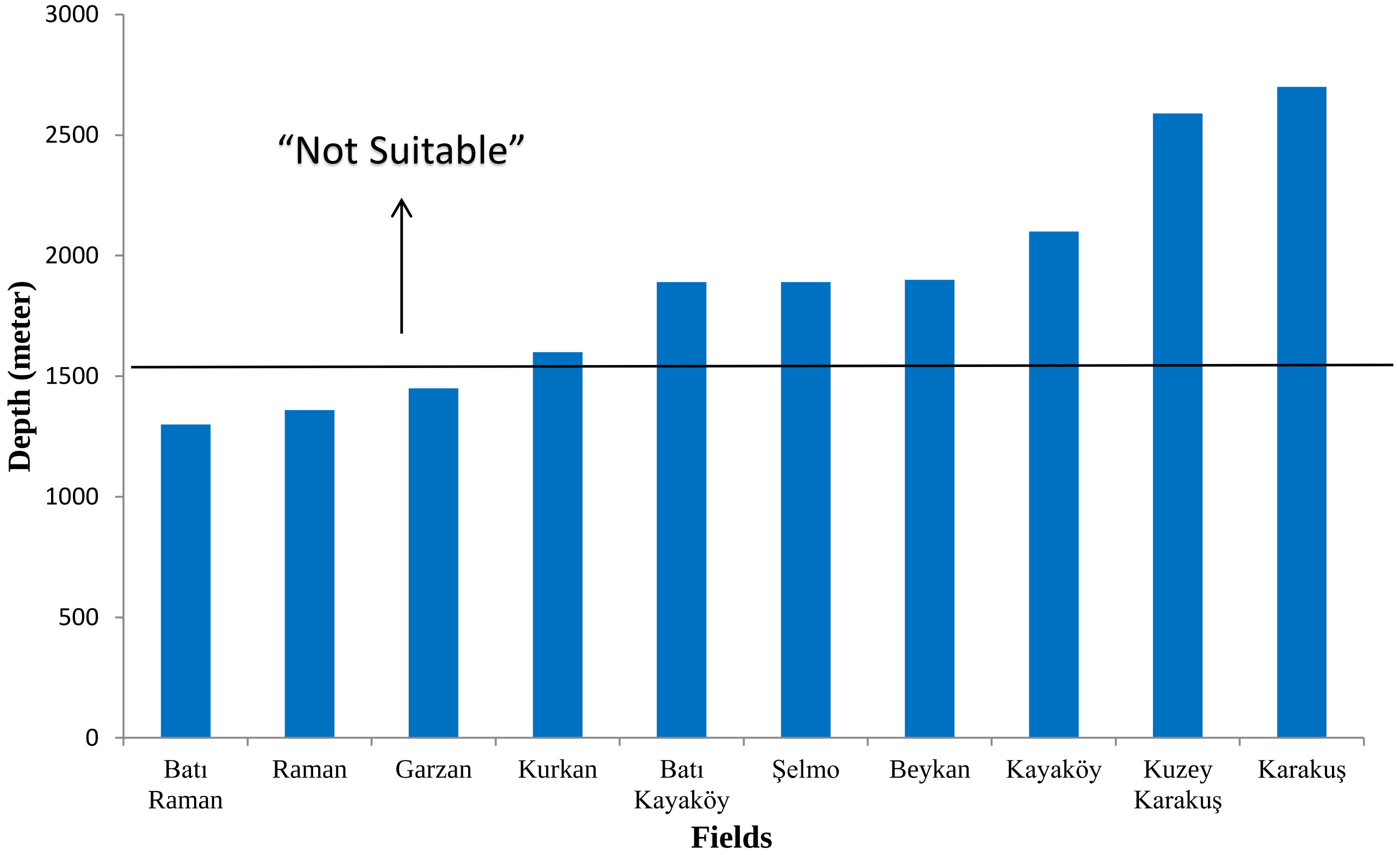
Suggestions for Turkey

Reservoir Properties of Remarkable Crude Oil Fields of Turkey



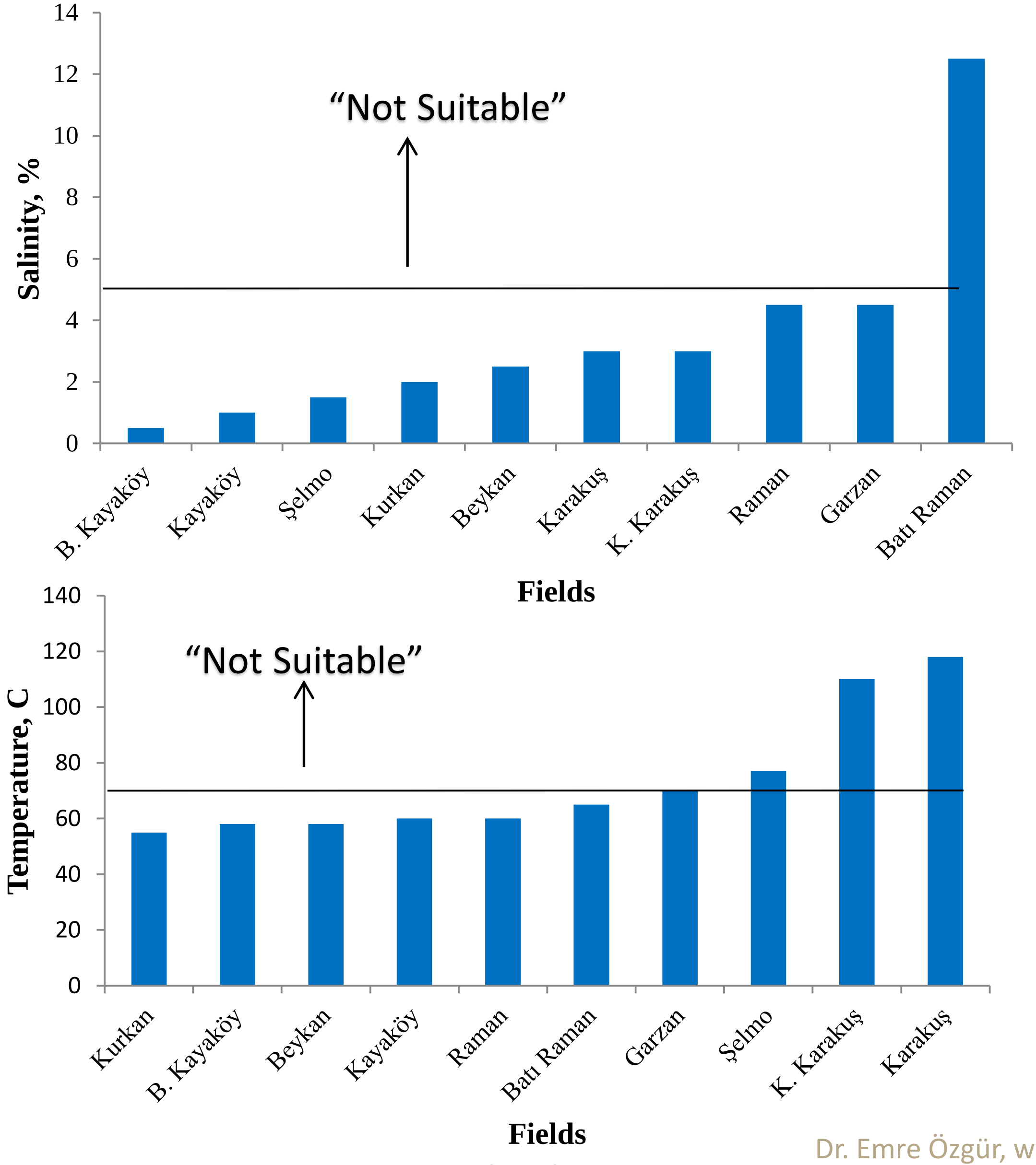
Field	Formation	Ø	k, md	Depth, m	Salinity (1000 ppm)	T,°C	API	μ, cp
Raman	limestone	14	50	1360	40	60	18	60
B. Raman	limestone	18	58	1300	120	65	13	600
Kurkan	limestone	15	9	1600	20	55	31	9
B. Kayaköy	limestone	17	4	1890	5	58	35	5
Beykan	limestone	12	1	1900	25	58	33	4
Şelmo	dolomitic limestone	7	100	1890	12	77	34	3
Karakuş	dolomitic limestone	6	100	2700	30	118	30	3
Garzan	limestone	11	15	1450	45	70	24	7
Kayaköy	limestone	15	2	2100	10	60	38	3
K. Karakuş	dolomitic limestone	6	100	2590	25	110	30	3

Suggestions for Turkey



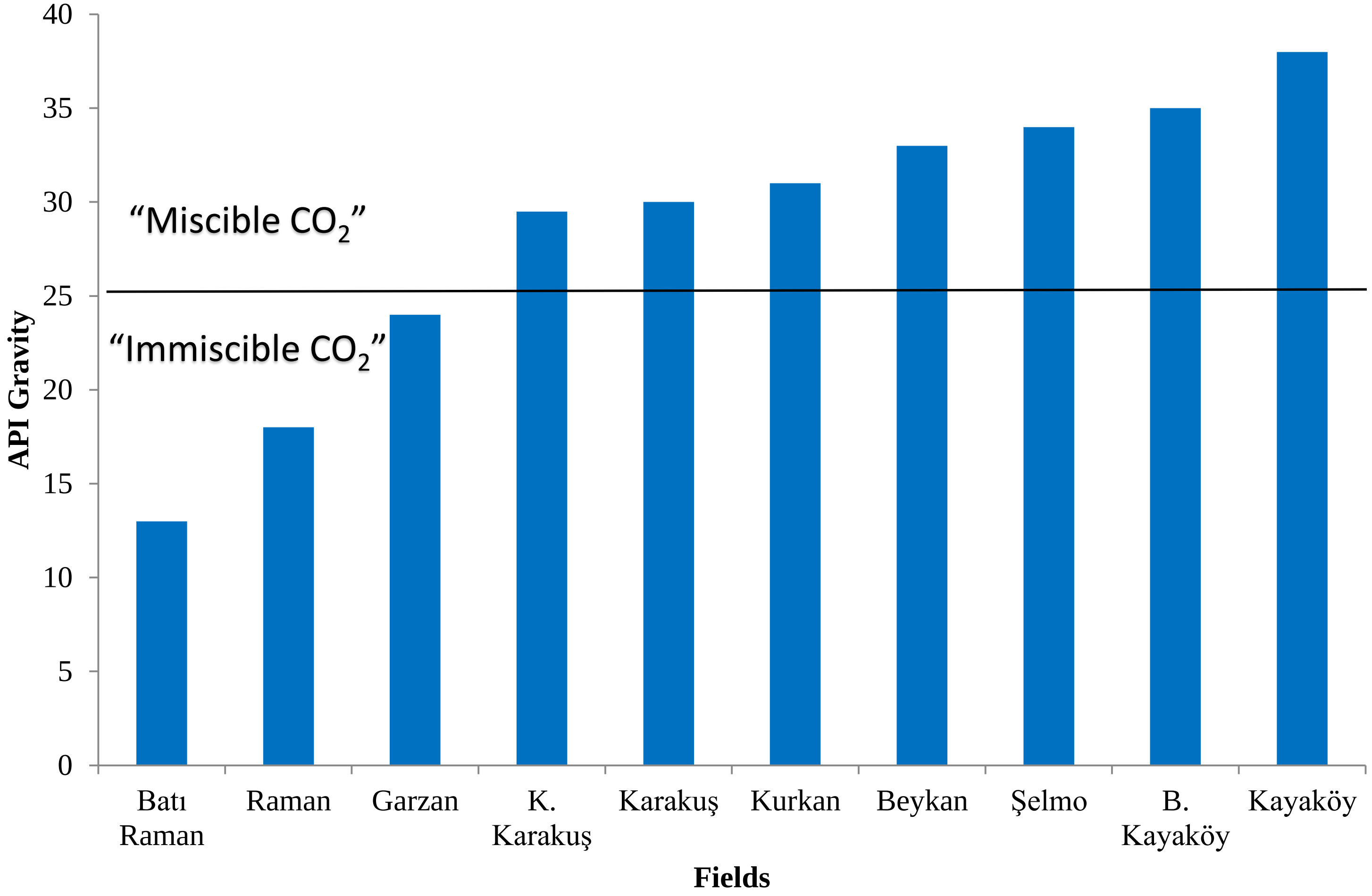
Steam Injection

Suggestions for Turkey



Microbial Injection

Suggestions for Turkey



CO_2 Injection

Suggestions for Turkey

Prediction on EOR Potential of Remarkable Turkish Crude Oil Fields

Field Name	Original Reserve	Recoverable Reserve	Recovery Factor	EOR Method	New Recovery Factor	Extra Oil Production
Raman	615,3	146,9	23,9	Imm.	33,9	61,7
Batı Raman	1841	192,9	10,5	Imm.	12,0	28,0
Kurkan	287	67,3	23,4	Mis.	38,4	42,9
Batı Kayaköy	225,6	63,4	28,1	Mis.	43,1	33,8
Beykan	432,8	89,8	20,7	Mis.	35,7	64,7
Şelmo	539	99,3	18,4	Mis.	33,4	80,7
Karakuş	209,1	61,6	29,5	Mis.	44,5	31,4
Garzan	199,1	46,5	23,4	Imm.	33,4	20,0
Kayaköy	99,9	31,20	31,2	Mis.	46,2	15,0
Kuzey Karakuş	87,8	42,2	48,1	Mis.	55,0	6,1
Toplam	4536,6	841,1	18.5 (avg.)	-	27.0 (avg.)	384,4

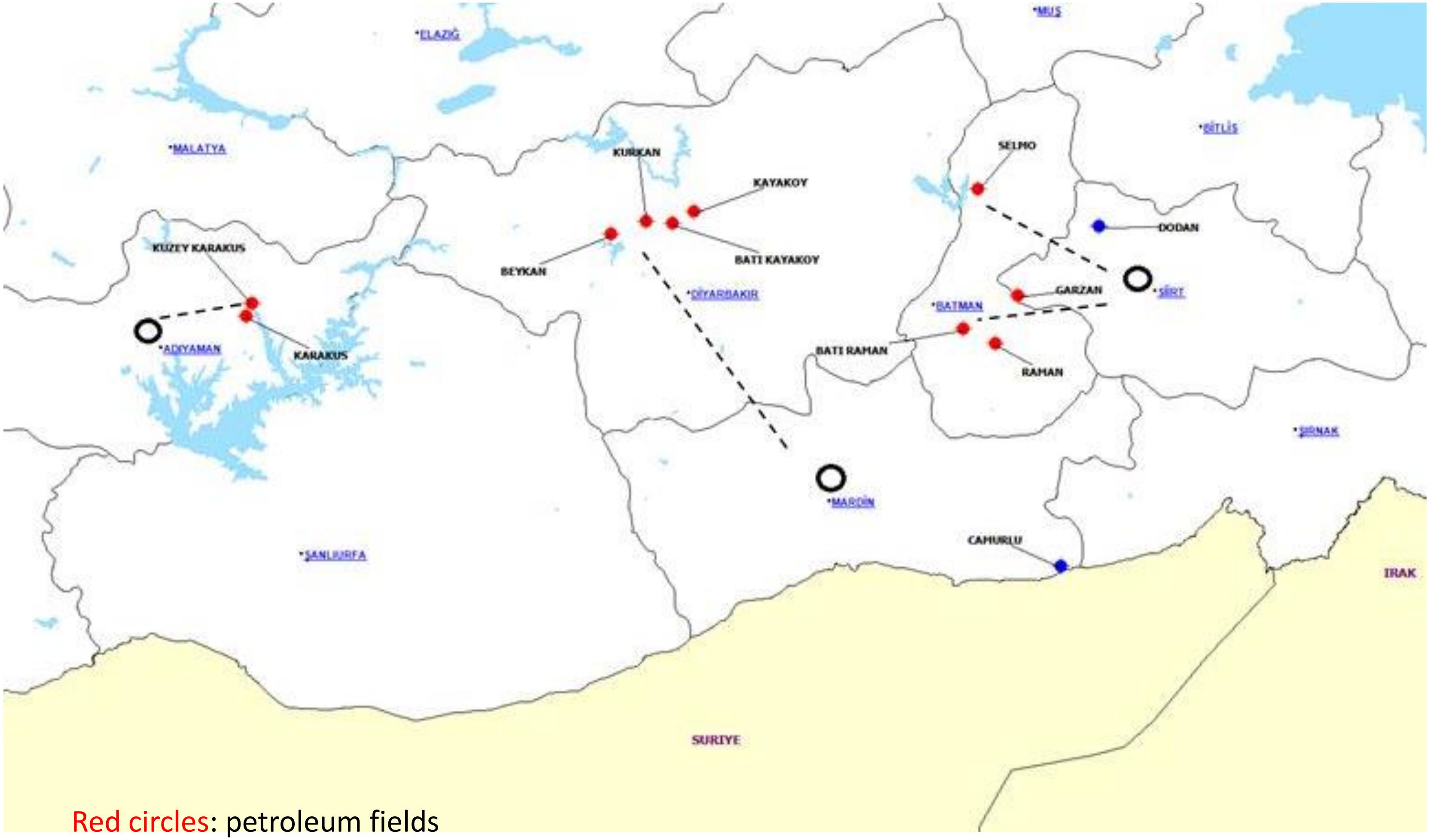
(Reserves and production amounts are presented in "million barrel")

Imm.: Immiscible CO_2 Injection

Mis.: Miscible CO_2 Injection

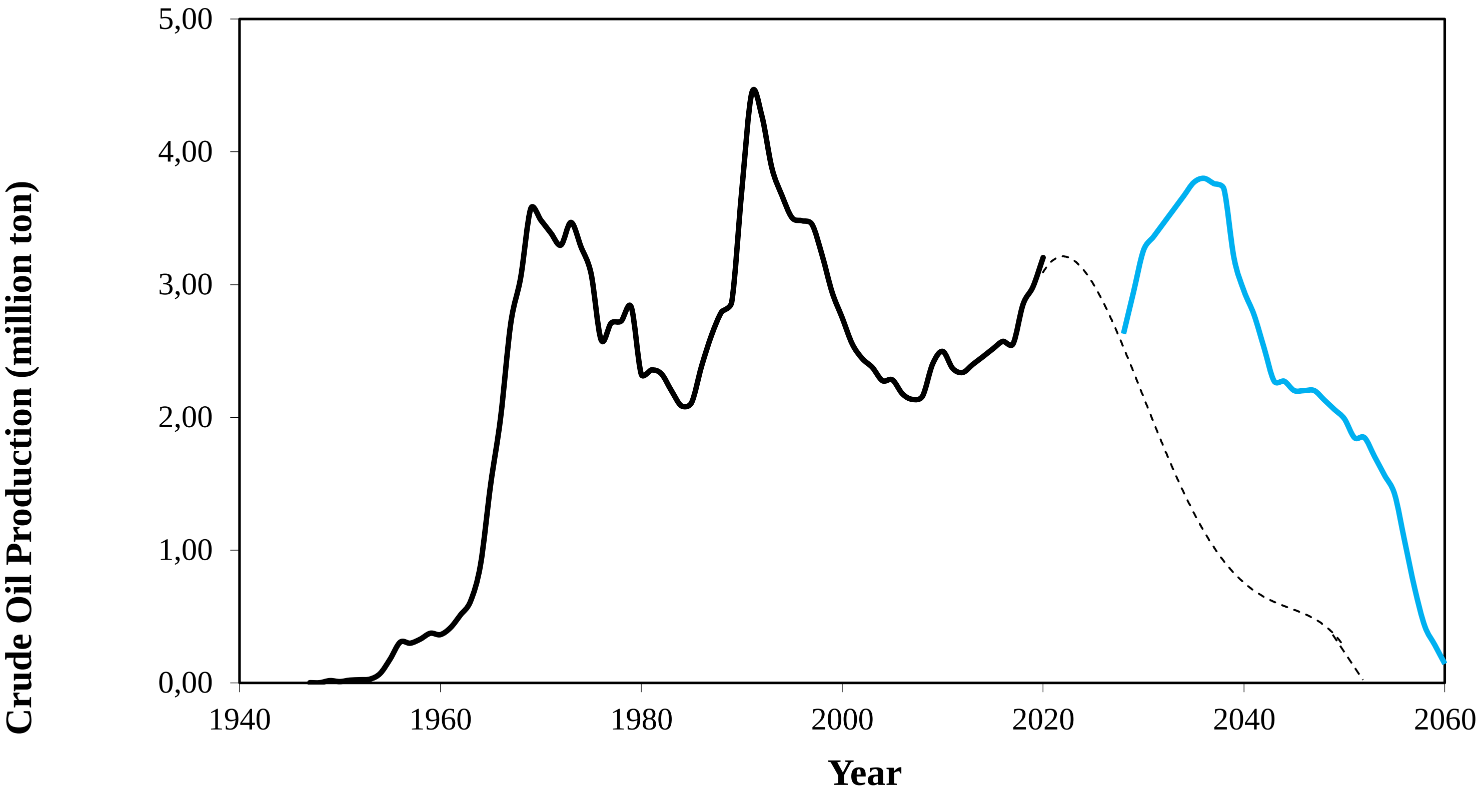
Suggestions for Turkey

Proposed CO_2 Pipelines



Red circles: petroleum fields
Blue circles: CO_2 fields
Black circles: CO_2 emitting cement factories
Black lines: proposed pipelines

Suggestions for Turkey



Dashed line: oil production forecast
Blue line: oil production forecast with EOR production)

Fields: Remarkable 10 fields

Recommended EOR Method: Miscible/Immiscible CO_2 Injection

Extra Crude Oil Production Potential: 384,4 million barrel

Enhanced Oil Recovery

Summary:

- There are currently 132 crude oil fields in Turkey and 10 of them (Batı Raman, Raman, Kurkan, Batı Kayaköy, Beykan, Şelmo, Karakuş, Garzan, Kayaköy, and Kuzey Karakuş) are remarkable whose recoverable reserves over 25 million barrels. There is currently one active immiscible CO_2 EOR Project performed for 35 years on the biggest crude oil field, Batı Raman, of Turkey forming 10% of the Turkish crude oil production. The application of immiscible / miscible CO_2 injection EOR methods on other fields together with the current one can provide about 385 million barrels of extra crude oil increasing the average recovery ratio of those 10 fields from 18.5% to 27%. This may extend the depletion of crude oil to the years 2060-2065 from the presently expected 2040-2045.

- One word for the pilot application of other EOR methods for research purpose: Raman oil field seems ideal for microbial flooding. Karakuş and Kuzey Karakuş fields seem ideal for smart water injection.

- The reduction in the royalty tax for the crude oil production by EOR would be a good motivation for oil companies. Considering lower crude oil prices, decreasing crude oil production trend and difficult geological conditions for petroleum exploration in Turkey, the introduction of such a regulation may lead to positive results in the long term. (e.g.: Hungary, Czechia, Slovakia – no or very low royalty for EOR production)

Enhanced Oil Recovery

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- 21. Yüzyılda Petrol ve Doğal Gaz Mühendisliği, Gazi Kitabevi, 2020 (In Turkish)