Reservoir Fluid Behavior, Production Trends and Analysis

Core Lab™

RESERVOIR OPTIMIZATION

Overview

- Fluids: Why? When? What? Who?
  - Reservoir Engineering 101
  - Phase Behavior basics
  - Production Trends
  - PVT, Flow Assurance, EOR apps
  - Experimental theories, Mathematics
- Blueprint for fluids program
- Value of Fluids Testing

Why Fluids?

"During the movement of oil and gas to the surface, the temperatures and pressures to which they are subjected change significantly. As a result, their physical and chemical properties undergo many radical changes as well. The economic value of produced oil and gas is dependent upon these properties, and the operator finds it invaluable to be able to predict handling and producing techniques which will allow him to produce his reserves in a form that will provide a maximum profit."

- Kim Kardashian

What? Why? When? Who?

- What is PVT/EOR analysis?
  - Pressure-Volume-Temperature
  - Physical and chemical properties
- Why?
  - Phase behavior, quality, flow assurance, EOR?
- When?
  - exploration/appraisal, development, production….early and often
- Who?
  - Asset teams, reservoir engineers, facility, production engrs, flow assurance specialists, petrophysicists

It starts here…

How much do I have?

$$N = Vb * \phi * So / \beta o$$

How much can I flow?

$$Q = K * \Delta P * A / (L * \mu)$$

Answer 4 Questions:

- What is the fluid behavior in the range of expected operating pressures and temperatures
- What is the market price of the discovered hydrocarbons and how can they be accommodated in export systems, ie, sample quality
- Does the fluid have the potential for hydrate, wax or asphaltene precipitation, ie, flow assurance
- Candidate for EOR?

Reservoir Fluid Behavior

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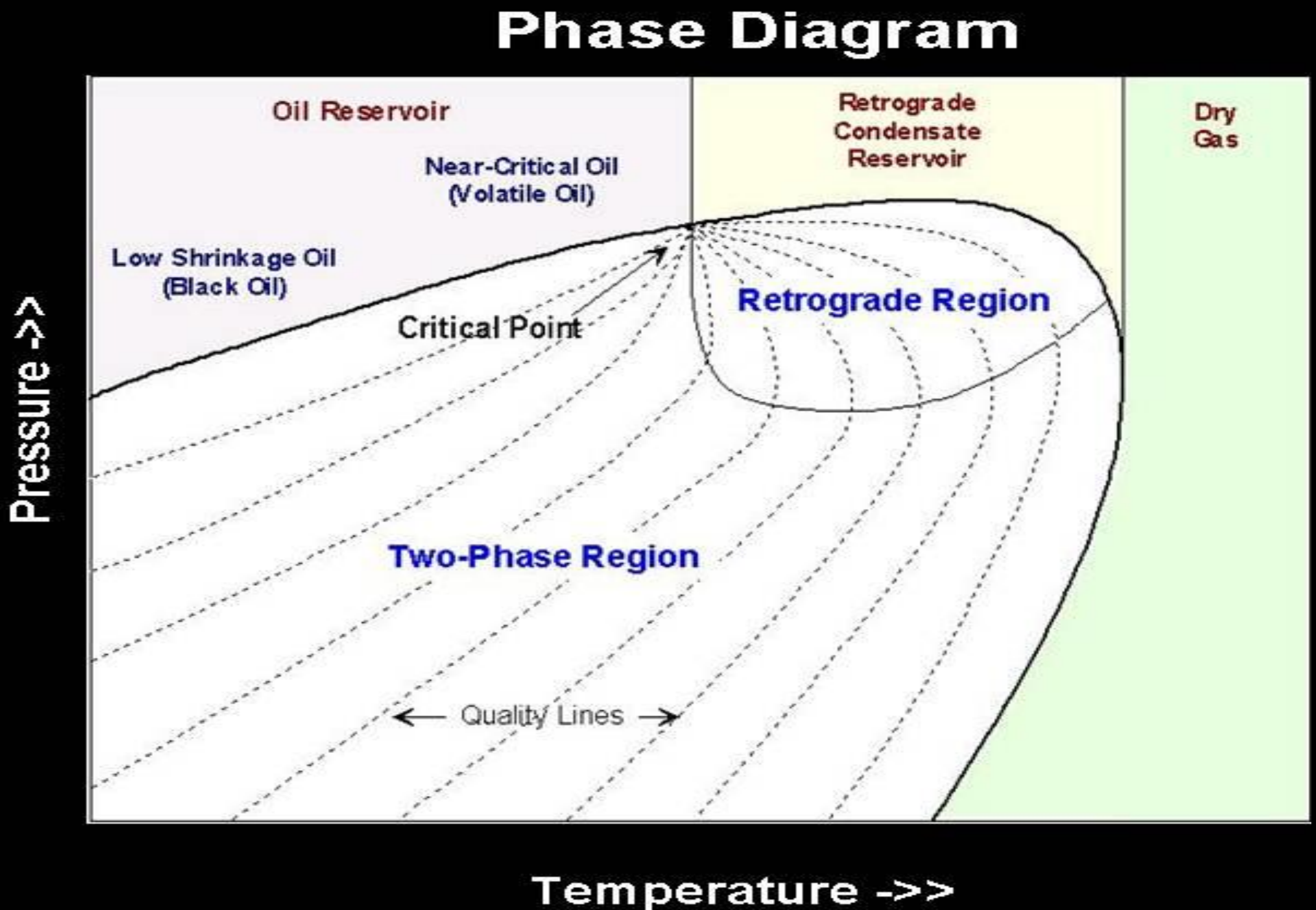

Black Oil Reservoirs

- Behavior
  - Heavy oil = lean gas
  - Viscosity discrepancy
  - Simple black oil models
  - Maturation = economic obstacles
- Production Trends
  - Consistent above bubble point
  - Preferential gas flow, GORs increase
  - Eventual production loss due to ‘energy loss’
  - Pressure trends
- Lab/operational issues
  - Emulsions, temp control, GC errors, hi viscosity errors

Summary of a Black Oil PVT Study

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Differential Liberation at 158 °F

Oil Properties

Pressure (psia)		Oil Density (g/cm^3)	Oil Compress. (V/V/psi) x 10^6	Oil Viscosity (cP)	Liberated GOR, R_l (scf/bbl)	Solution GOR, R_{sd} (scf/bbl)	Oil FVF, B_{od} (vol/resid. vol)	Solution GOR, R_s (scf/bbl)	Sep. Adj. FVF, B_o (vol/ST vol)
10,000		0.790	5.63	2.289	0	723	1.306	679	1.282
9338	**Reservoir**	**0.787**	**5.88**	**2.158**	**0**	**723**	**1.311**	**679**	**1.287**
9000		0.786	6.02	2.106	0	723	1.314	679	1.290
8000		0.781	6.46	1.944	0	723	1.322	679	1.298
7000		0.775	6.97	1.800	0	723	1.332	679	1.307
6000		0.769	7.56	1.694	0	723	1.342	679	1.317
5000		0.763	8.26	1.579	0	723	1.353	679	1.328
4120	**Saturation**	**0.757**	**9.28**	**1.498**	**0**	**723**	**1.364**	**679**	**1.339**
3250		0.774	5.84	1.797	140	583	1.303	548	1.283
2400		0.791	5.50	2.227	277	446	1.249	419	1.233
1500		0.812	5.25	2.936	422	301	1.191	283	1.180
750		0.831	5.04	3.904	545	178	1.141	168	1.134
150		0.850	4.84	5.562	659	64	1.088	60	1.085
15		0.866		6.322	723	0	1.044	0	1.044
15	at 60 °F	0.899	**API = 25.7**				1.000		

Vapor Properties

Pressure (psia)	Gas Density (g/cm^3)	Gas Z Factor (vol/vol at std)	Incr. Gas Gravity (Air = 1.00)	Cum. Gas Gravity (Air = 1.00)	Gas FVF, B_g (res bbl /mmscf)	Gas FVF, B_g (res cu ft / scf)	Total FVF, B_t (vol/resid. vol)	Calc. Gas Viscosity (cP)
3250	0.179	0.901	0.708	0.708	882	0.0050	1.426	0.022
2400	0.129	0.890	0.681	0.695	1179	0.0066	1.575	0.018
1500	0.077	0.906	0.664	0.684	1921	0.0108	2.001	0.015
750	0.038	0.933	0.681	0.684	3956	0.0222	3.294	0.013
150	0.009	0.985	0.876	0.717	20882	0.1172	14.851	0.012
15.025	0.002	1.000	1.607	0.795	212088	1.1908	154.308	0.009

Notes:

- Compressibility is calculated using the indicated and previous pressur
- The Separator Adjusted GOR and FVF represent the differentially liberated oil produced through the surface separators (see MSF)
- Sep. Adjusted Data using Muhammad A. Al-Marhoun method
- Gas MW = Vapor Gravity x Molecular Weight Air
- Standard Condition: 15.025 psia at 60 °F
- Atmospheric Step completed at Reservoir Temperature
- B_o = Oil Volume at P,T / Stock Tank Volume at 60 °F
- B_{od} = Oil Volume at P,T / Residual Oil Volume at 60 °F
- R_s = Gas Volume at Standard Conditions / Stock Tank Volume
- $B_t = B_o + [(\text{Total Liberated Vapor}, R_l) \times B_g] \times 10^{-6}$
- R_l is cumulative liberated gas / Residual Oil Volume
- Vapor Viscosity calculated with Lee-Gonzales Correlation
- Oil Viscosity measured using electro magnetic viscometer

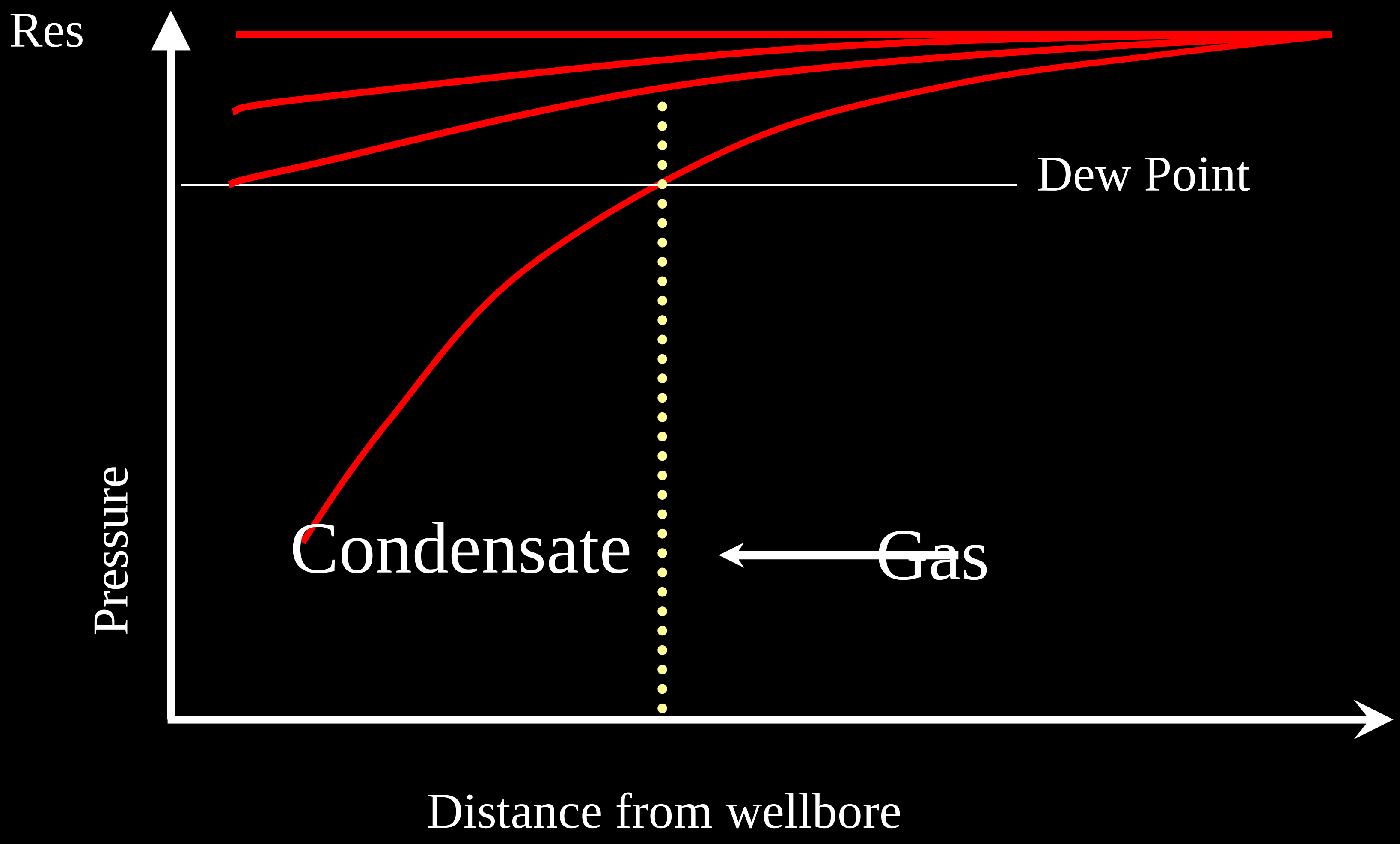
Black Oils – EOR applications?

- Miscibility experiments
  - Is it miscible with injection gas?
  - At what pressure?
- Does injection gas affect physical properties?
  - Viscosity reduction
- Multi-contact studies
  - Multiple recombinations of oil-injection gas
  - What's happening in front of, in back of, the 'front'

Gas-Condensate Reservoirs

- Behavior
  - Life is great…above dew point
  - Condensation begins, gas leaner
  - Condensate banking
- Production Trends
  - Gas volume pressure driven
  - Decrease due to condensation and condensate induced reduction in perm
  - Eventual increase due to higher gas perm
- Lab issues

Condensate 'Banking,



Gas Depletion Study

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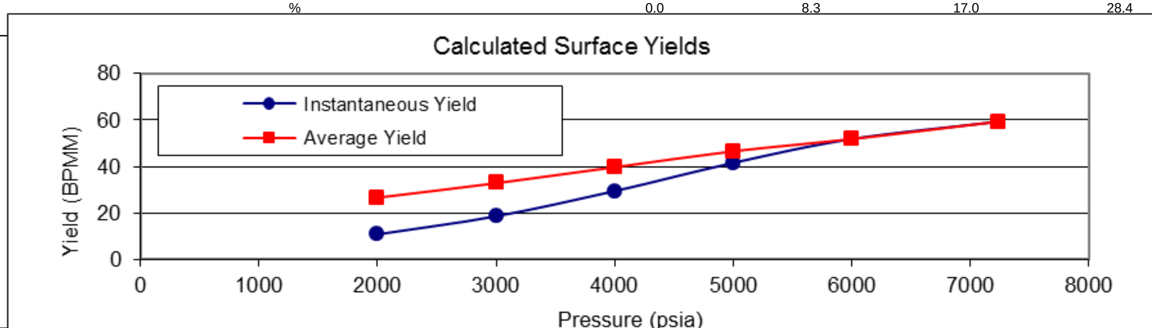
Calculated Surface Gas and Liquid Recovery

Experimental and Equation of State Predictions

		Pressure (psia)						
		Initial	7232	6000	5000	4000	3000	2000
Moles in PVT Cell			0.769	0.703	0.633	0.544	0.436	0.307
Fraction Vapor Liberated / Step			0	0.066	0.070	0.090	0.107	0.130
EOS Predicted Liquid Fractions								
1st Stage: 1015 psia, 96°F	(mole fraction)		0.061	0.056	0.048	0.036	0.024	0.015
2nd Stage: 515 psia, 72°F	(mole fraction)		0.861	0.858	0.856	0.854	0.852	0.851
3rd Stage: 105 psia, 104°F	(mole fraction)		0.829	0.826	0.825	0.823	0.823	0.822
Stock Tank, 15 psia, 60°F	(mole fraction)		0.950	0.949	0.948	0.948	0.947	0.946
Predicted Liquid Molar Volume	(cc/mole)		184.0	175.9	167.2	158.4	150.9	145.3

Calculated Surface Recovery

		Initial	7232	6000	5000	4000	3000	2000
Initial Reservoir Fluid in Place	mscf	1000	1000					
Vapor Produced / Step	mscf		0.0	86.1	90.4	116.6	139.4	168.8
Cumulative Vapor Produced	mscf		0.0	86.1	176.5	293.1	432.5	601.3
Predicted Surface Liquids	stb		0.0	4.3	3.6	3.4	2.6	1.8
Cumulative Surface Liquids	stb		0.0	4.3	7.9	11.3	13.9	15.7
Predicted Surface Vapor	mscf		0.0	82.8	87.5	113.8	137.2	167.2
Cumulative Surface Gas	mscf		0.0	82.8	170.4	284.1	421.3	588.5
Instantaneous Yield	stb/mmscf		59.3	51.9	41.6	29.5	18.6	10.9
Average Yield	stb/mmscf		59.3	51.9	46.6	39.7	32.9	26.6
Instantaneous GCR	scf/stb		16859	19282	24033	33906	53634	91744
Average GCR	scf/stb		16859	19282	21462	25159	30417	37546
Gas Recovery Factor	%		0.0	8.3	17.0	28.4	42.1	58.8
Liquid Recovery Factor							24.4	27.6



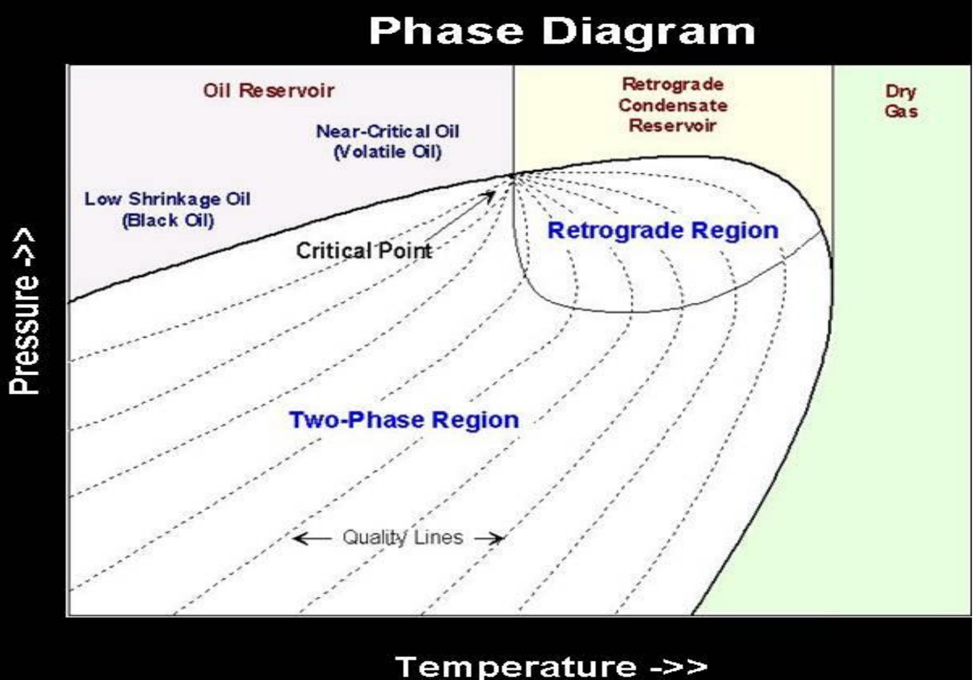
Notes:

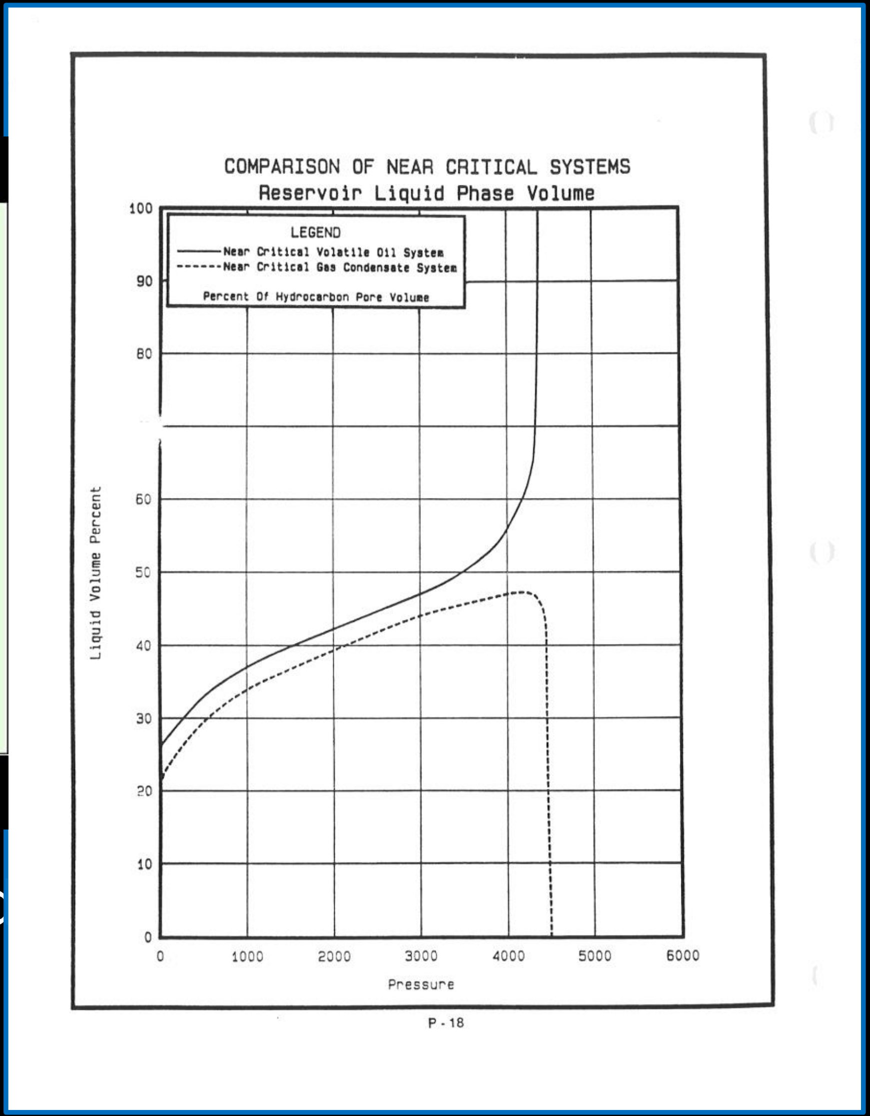
Gas-Condensates – EOR applications?

- Gas revaporization
  - Can a lean gas revaporize the condensate bank?
  - …and maybe sweep a little?
- Gas storage?
  - Do I need facilities to handle produced liquids?

Near-Critical Fluids: Volatile Oils, 'Rich' Gases

- Light oil, heavy gas





- Handled by compositional
phases, compositional grad

Near Critical Behavior

- Composition: heavies, lights and mid-range
- Light liquid –heavy gas
- Large initial shrinkage and gas liberation
- Gas/liquid comps similar
  - Gas volumes increase SLIGHTLY
  - ‘oil’ volumes decrease SLIGHTLY
- Volatile Oils:
  - gas/oil viscosity increases, less preferential flow
  - Separator liquid = 1 part oil + 3 parts condensate

PVT/EOR Project Flow

- PVT Analysis
  - Compositions, Psat, phase behavior
- MMP determination
  - Injection gas, determine miscibility
- Swelling studies
  - Equilibrium mixing, P-V, viscosity, flow assurance?
- Multi-Contact Studies
- Gas revaporization/cycling
- Core Flood/Soaking studies
- EOS-Reservoir Modeling

Flow Assurance/Oil Quality

- Quality – Geochemistry
  - Source rock, thermal maturation, biodegradation, compartmentilization
- Screening – Dead Oil Flow Properties
  - Pipeline specifications
- Paraffin and Asphaltenes
  - Paraffin – temp control, chemicals, pipeline issue
    - Lab program: Temperature variability
  - Asphaltenes – density control, reservoir issue
    - Lab program: pressure depletion onsets

Blueprint for Fluids Program

- Proper sampling
- Chemistry
- Physical properties
  - fluid flow assurance, viscosity etc, dead oil analyses
- Reservoir depletion simulation
  - CME, Diff Lib, CVD
- Surface recovery simulation
  - separator tests
- Mathematics

How is it all used?

- Reserves - Bo, Rs
  - oil and gas, fluid energy, recovery efficiency
- Project Revenue – crude oil prices

How much do I have?

$$N = Vb * \phi * So / \beta o$$

How much can I flow?

$$Q = K * \Delta P * A / (L * \mu)$$

  - need for waterflood, gas injection
- Facility upgrades
- Allocation – who gets what?
- More fluids analysis=more information=more ammunition=better models=MORE EFFICIENT USE OF ASSETS=OPTIMAL $$$ SPENT=LOWER F&D COSTS

Thanks

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Questions?