

# **Flow in Porous Media**

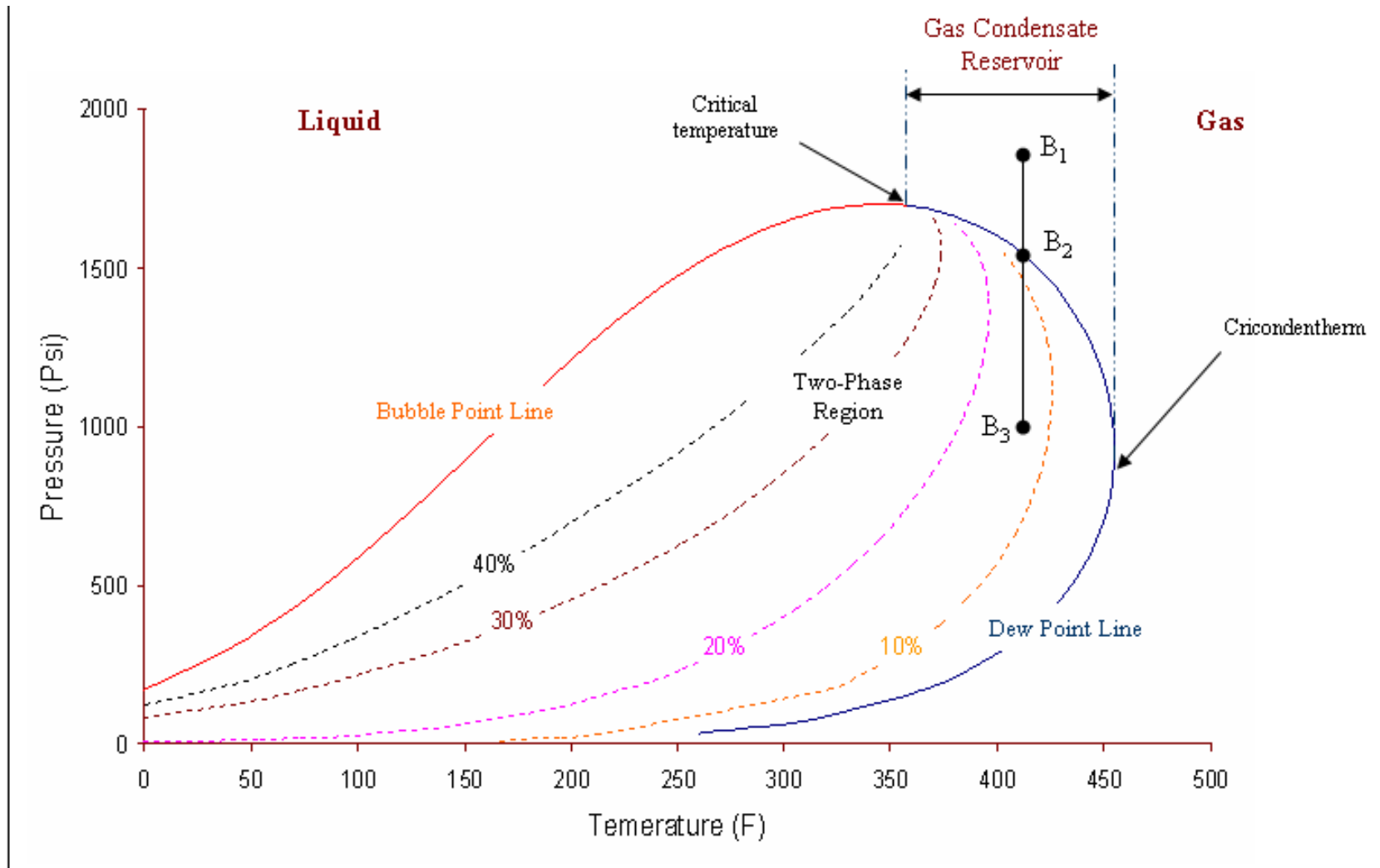
## **Module 3.c**

### **Fundamental of Two Phase Flow in Porous Media**

**Two phase flow in gas condensate reservoirs**

# Gas Condensate Reservoirs

## ➤ Initial Reservoir (P & T) Conditions



# Gas Condensate Reservoirs- Composition

Dominant composition: C1

Heavier composition < 15%

**TABLE 2.1—COMPOSITION AND PROPERTIES OF SEVERAL RESERVOIR FLUIDS**

Component	Composition (mol%)					
	Dry Gas	Wet Gas	Gas Condensate	Near-Critical Oil	Volatile Oil	Black Oil
CO <sub>2</sub>	0.10	1.41	2.37	1.30	0.93	0.02
N <sub>2</sub>	2.07	0.25	0.31	0.56	0.21	0.34
C <sub>1</sub>	86.12	92.46	73.19	69.44	58.77	34.62
C <sub>2</sub>	5.91	3.18	7.80	7.88	7.57	4.11
C <sub>3</sub>	3.58	1.01	3.55	4.26	4.09	1.01
<i>i</i> -C <sub>4</sub>	1.72	0.28	0.71	0.89	0.91	0.76
<i>n</i> -C <sub>4</sub>		0.24	1.45	2.14	2.09	0.49
<i>i</i> -C <sub>5</sub>	0.50	0.13	0.64	0.90	0.77	0.43
<i>n</i> -C <sub>5</sub>		0.08	0.68	1.13	1.15	0.21
C <sub>6(s)</sub>		0.14	1.09	1.46	1.75	1.61
C <sub>7+</sub>		0.82	8.21	10.04	21.76	56.40
			Properties			
<i>M</i> <sub>C<sub>7+</sub></sub>		130	184	219	228	274
<i>γ</i> <sub>C<sub>7+</sub></sub>		0.763	0.816	0.839	0.858	0.920
<i>K</i> <sub>wC<sub>7</sub></sub>		12.00	11.95	11.98	11.83	11.47
GOR, scf/STB	∞	105,000	5,450	3,650	1,490	300
OGR, STB/MMscf	0	10	180	275		
<i>γ</i> <sub>API</sub>		57	49	45	38	24
<i>γ</i> <sub>g</sub>		0.61	0.70	0.71	0.70	0.63
<i>p</i> <sub>sat</sub> , psia		3,430	6,560	7,015	5,420	2,810
<i>B</i> <sub>sat</sub> , ft <sup>3</sup> /scf or bbl/STB		0.0051	0.0039	2.78	1.73	1.16
<i>ρ</i> <sub>sat</sub> , lbm/ft <sup>3</sup>		9.61	26.7	30.7	38.2	51.4

(Monograph vol. 20, SPE)

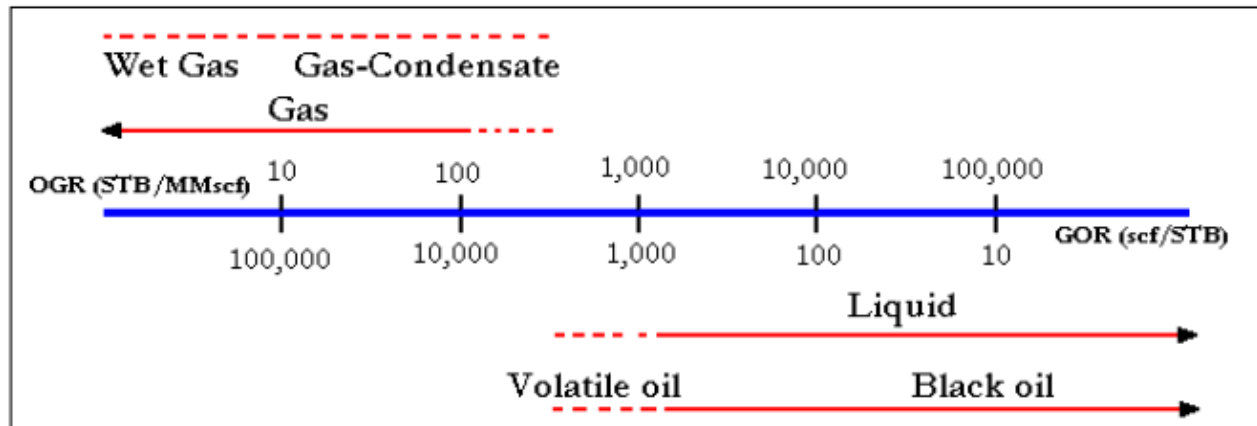
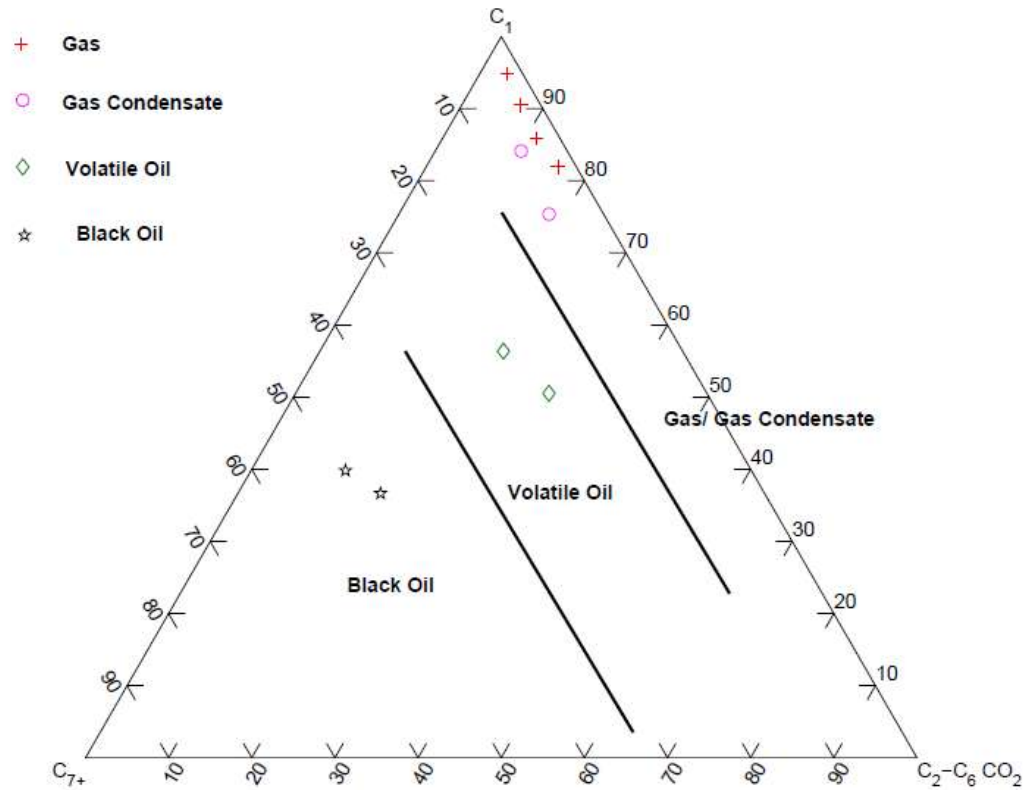
# Gas Condensate Reservoirs- Field Indicators

(McCain, 1990)

<b>GOR, SCF/STB</b>	<b>Surface Yield, STB/MMSCF</b>	<b>Type</b>
3,300	300	Highly Rich
150,000	7	Highly Lean

\*GOR > 50,000 treated as a Wet gas

# Ternary Visualization of Hydrocarbon Classification



# Condensate Drop-Out

1. Reduces the condensate recovery (immobile oil phase)
2. May result in poor well deliverabilities due to condensate blockage

- The effect of condensate blockage depends on:
  - (1) relative permeabilities,
  - (2) PVT properties, and
  - (3) how the well is being produced (constant rate vs. constant BHFP).
- The reduced wellbore deliverability due to condensate blockage is only important when BHFP reaches a minimum (dictated by surface pressure constraints) and the well is forced to go on decline.

# Why Condensate Drop-Out is important?

1. Lower condensate recovery (immobile oil phase)
2. May result in poor well deliverabilities

## Condensate dropout without severe productivity decline (Schlumberger 2005-2006 report)

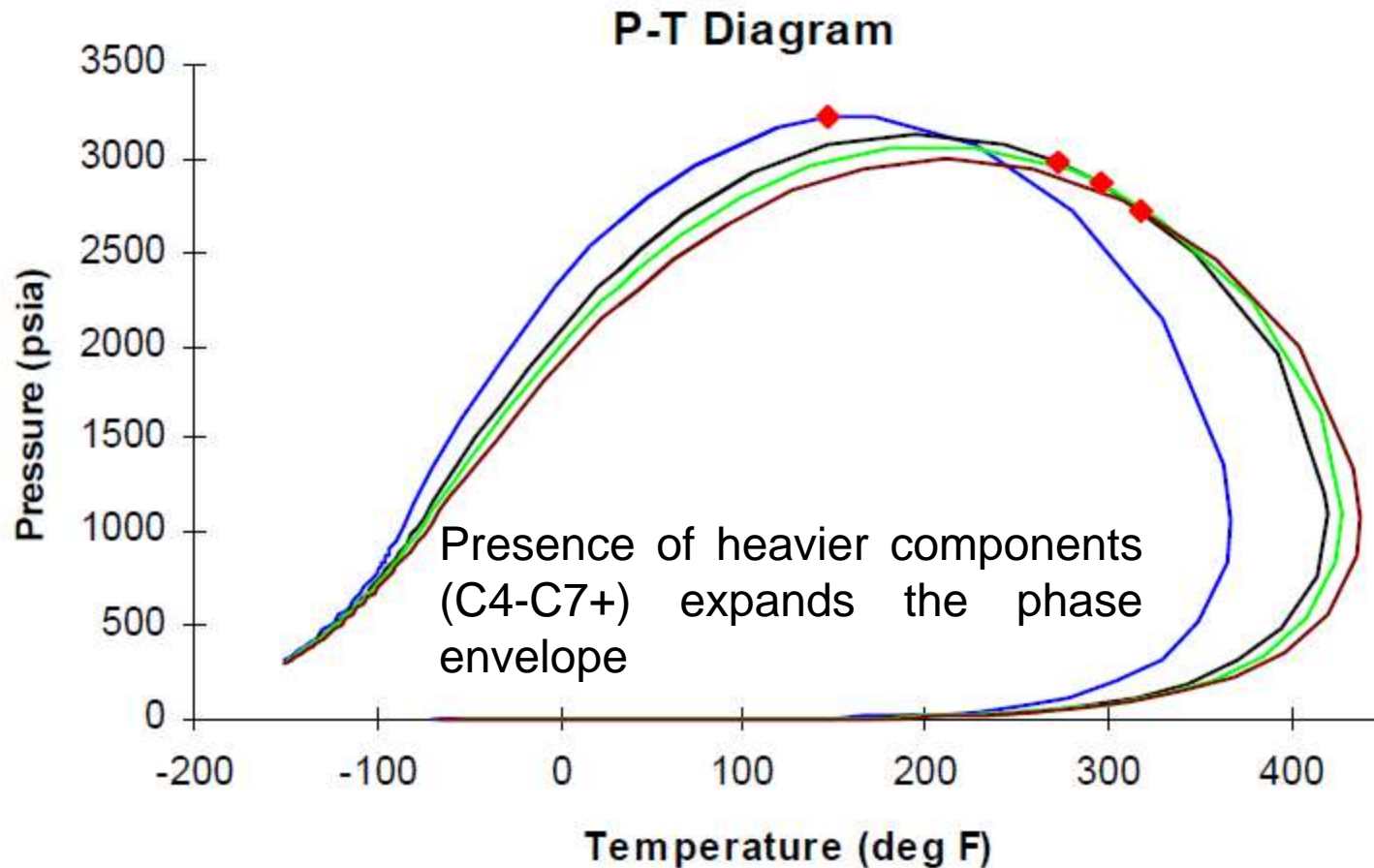
- In high productive or fractured reservoirs
- Vuktyl GC field in the Komi Republic, Russia
- Loss of valuable intermediate and heavier components (855 million bbl)

## Condensate dropout with severe productivity decline (SPE 28749, 1994)

- Arun Indonesian giant GC field; 23000 acres
- Thick limestone formation; local thickness of 1,000ft
- Rapid decline after approximately 10 years; some of productivities decline down to 50%.
- Confirmed through pressure transient response and PI test

## Shift in Phase Envelope of Gas-Condensate Mixture as the Heavier Components Are Dropped Out in Reservoir

In reality the composition of the overall reservoir fluid does not remain constant. This results in a shift in the phase envelope, and leads to less revaporization at lower pressures

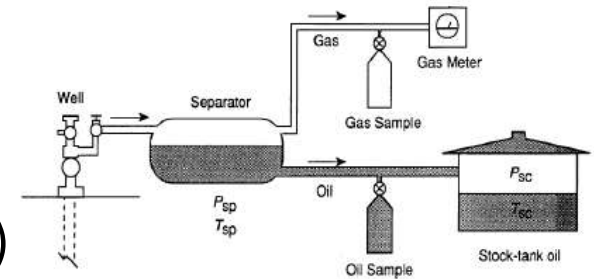




# Gas Condensate Reservoirs- Experimental Work

## 1. PVT Sampling

- *Captured at single-phase period*
  - ✓ Conventional surface (Recombination method)
  - ✓ Novel down-hole sampling (Schlumberger, 2001)



## 2. Lab Experiments:

- **CCE**
  - ✓  $P_{dew}$
- **CVD**
  - ✓ Liquid dropout curve
  - ✓ Single phase gas deviation factor, directly measured
  - ✓ Viscosities, directly measured
  - ✓ 2-phase gas deviation factors, indirectly calculated
  - ✓ Vaporized oil-gas ratio below  $P_{dew}$ , indirectly calculated
  - ✓ Material Balance calculations (L.P. Dake, 2001)

Highly important in EOS tuning and reservoir fluid characterization

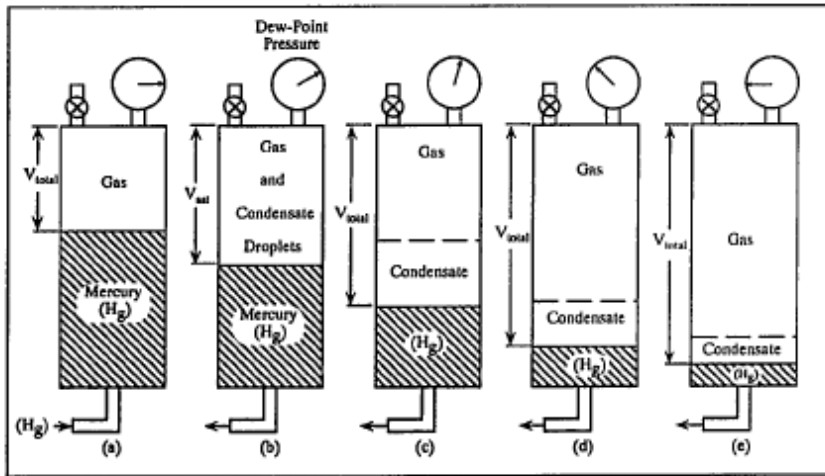


Figure 4.2: Constant Composition Expansion or Flash Liberation of Reservoir Fluid in PVT Test Cell

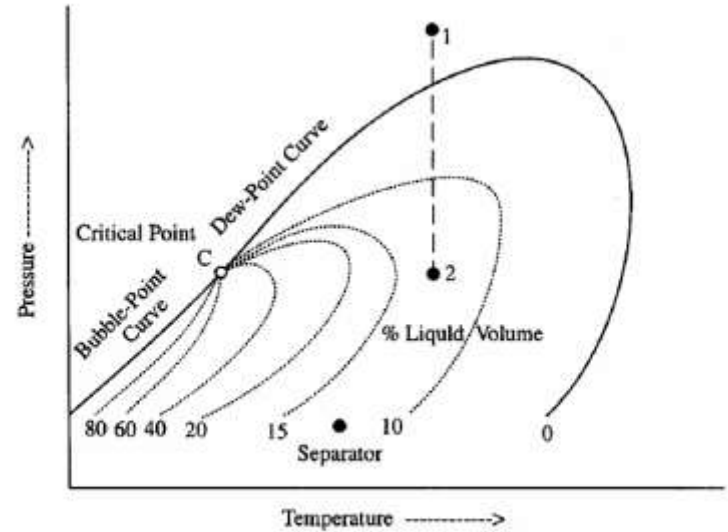


Figure 2.6: Phase Diagram of Gas Condensate<sup>12</sup>

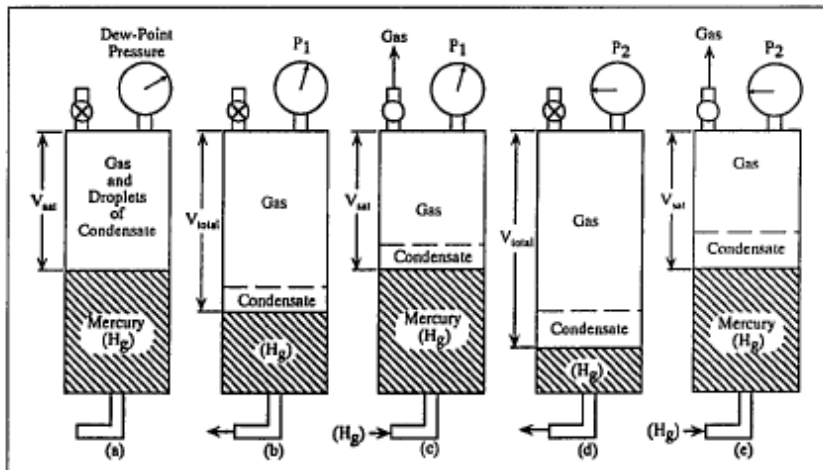


Figure 4.4: Constant Volume Expansion of Reservoir Fluid in PVT Test Cell

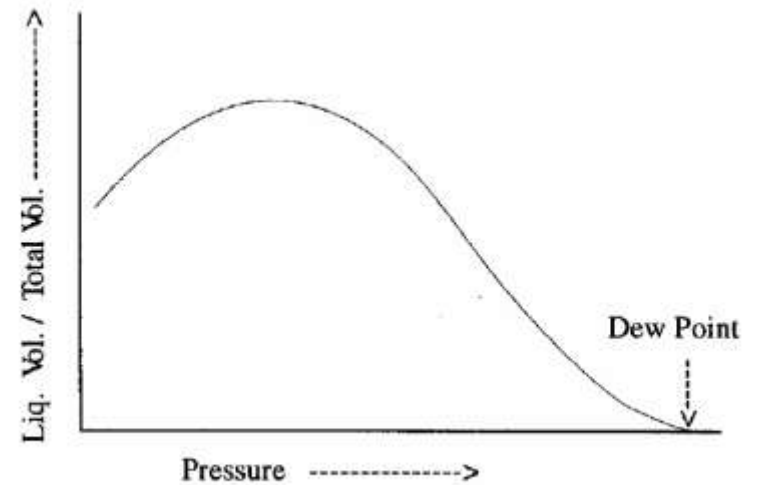
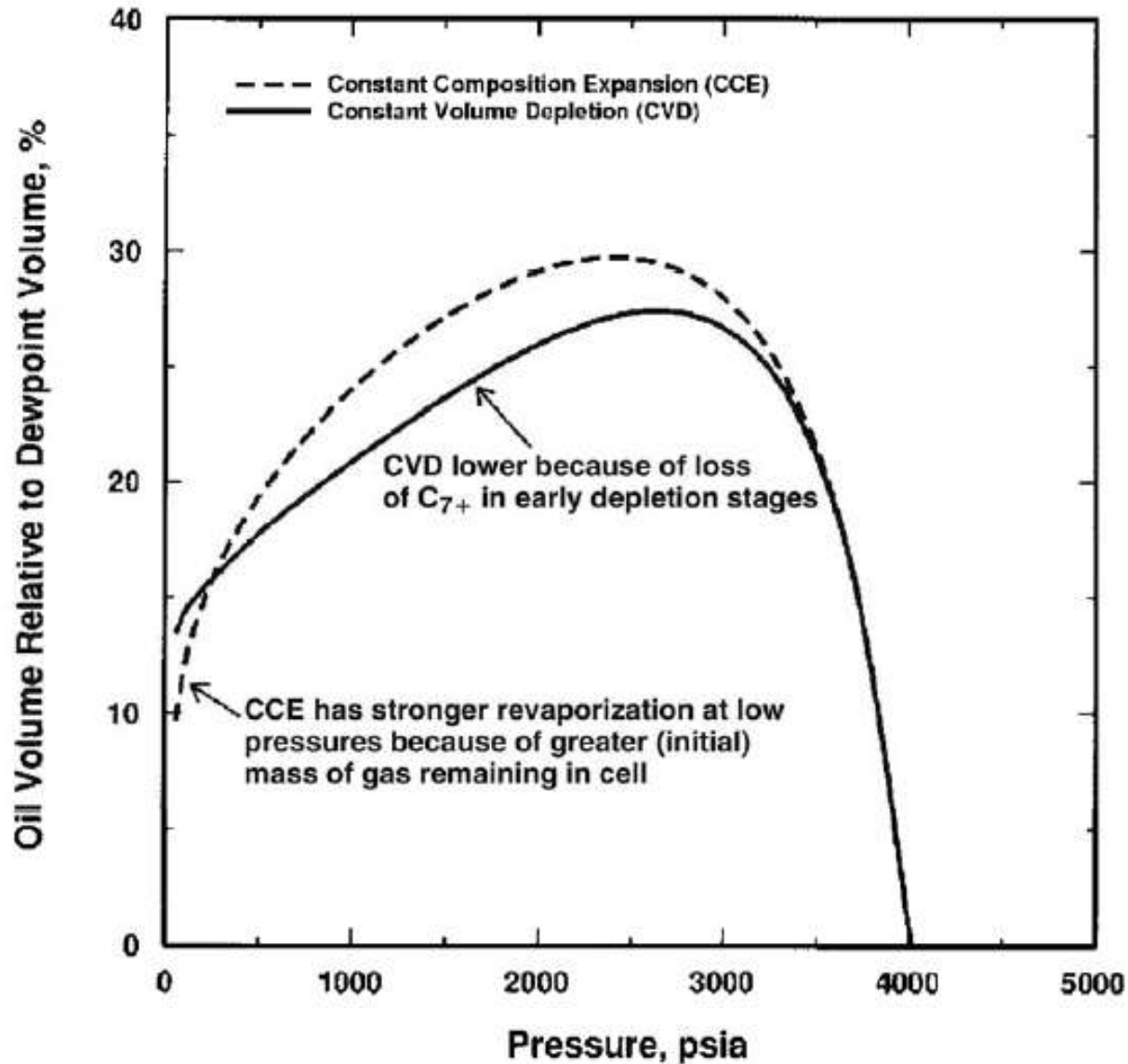


Figure 2.7: Liquid drop-out Behavior of Gas Condensate<sup>12</sup>

# Constant Composition vs. Constant Volume



# Drawdown Behavior

Fluid flow towards the well in a gas condensate reservoir during depletion can be divided into three concentric main flow regions, from the wellbore to the reservoir (Fevang, 1995):

- ❑ **Near-wellbore Region 1:** Around the wellbore, region with high condensate saturation where both gas and condensate are flowing simultaneously.
- ❑ **Condensate buildup Region 2:** Region where the condensate is dropping out of the gas. The condensate phase is immobile and only gas is flowing.
- ❑ **Single phase gas Region 3:** Region containing only the original reservoir gas.

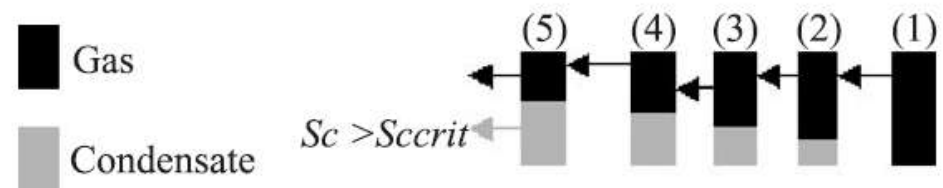
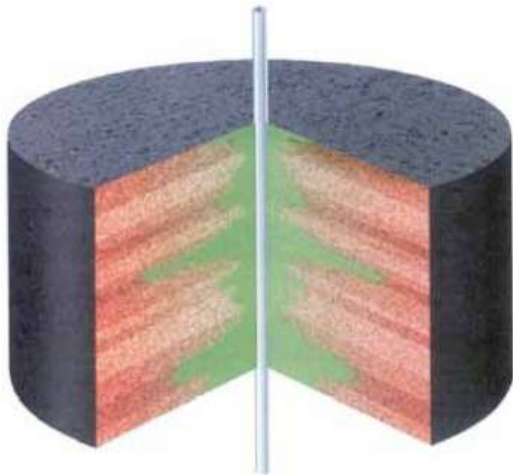
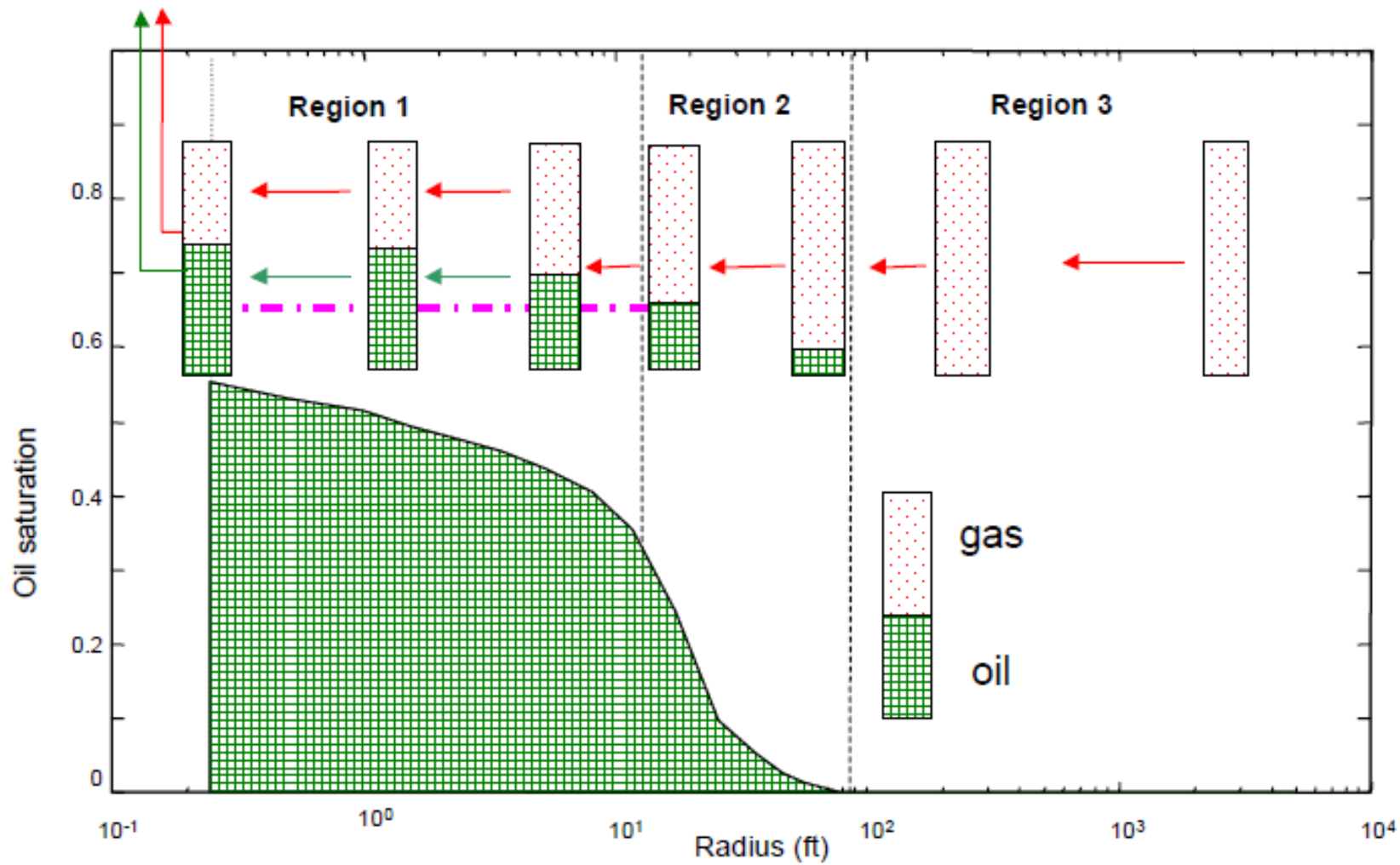
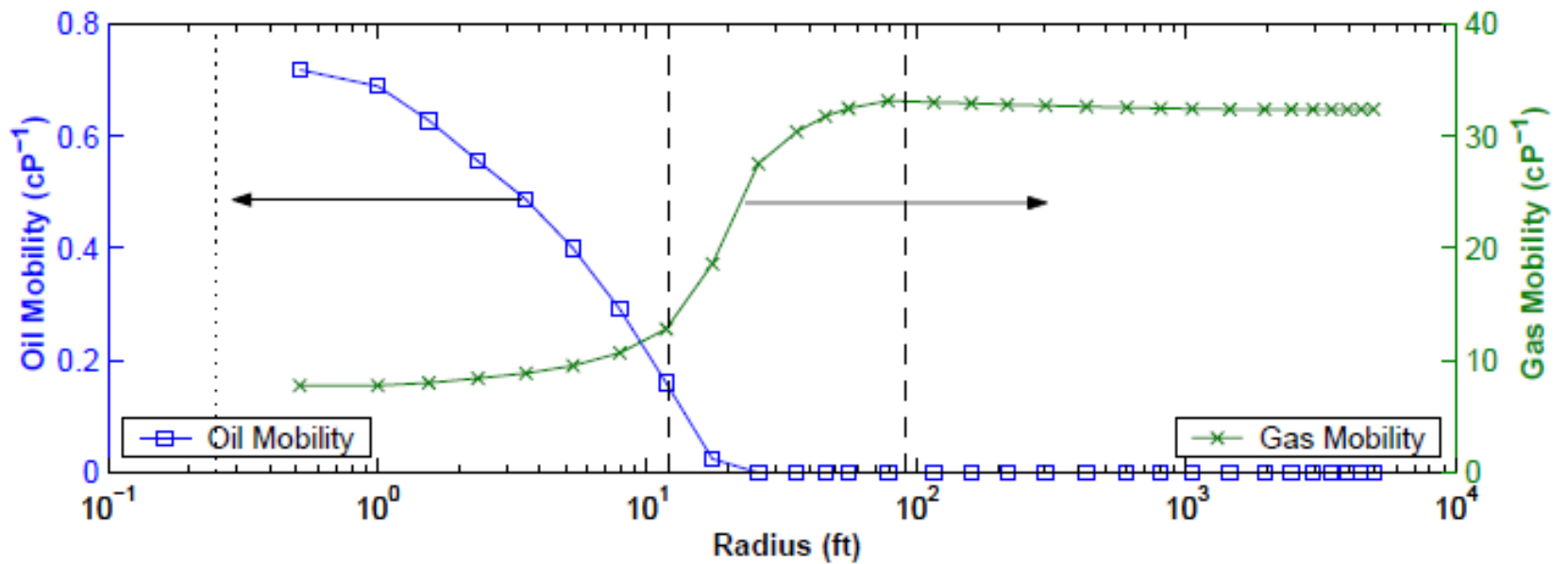
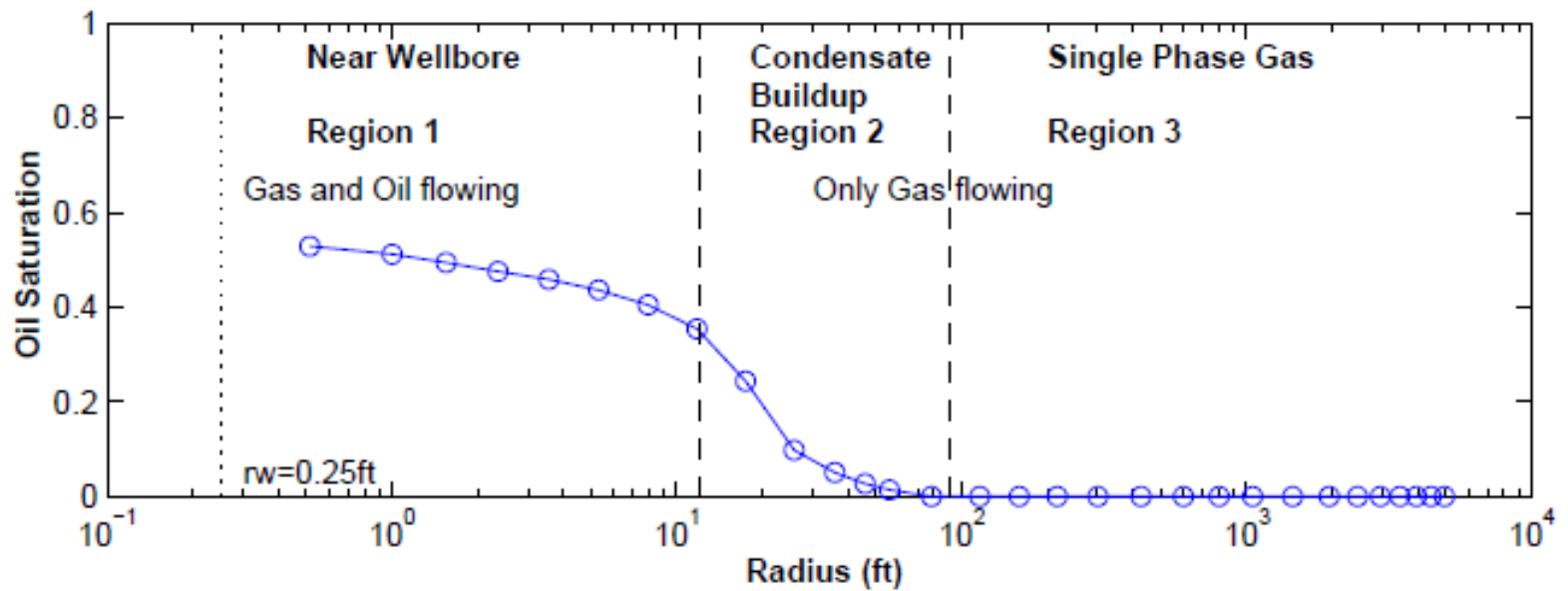


Fig. 1. Dynamic phase behavior in a gas condensate reservoir.





# Region 1

- ❑ Region 1 will always (and only) exist when  $P_{wf}$  (BHFP) is below the dew point. A short transition period is required to build up steady-state saturations in Region 1.
- ❑ Size: The size of this region varies with time and richness of the initial reservoir fluid. The size is typical 50-100 feet (15-30 meter) for leaner gas condensates and 200-500 feet (50-150 meter) for richer gas condensates.
- ❑ Oil Saturation: The saturation in Region 1 is usually in the range of 40-60%. The oil saturation is established such that the oil drooping of the reservoir gas has enough mobility to move together with the reservoir gas (no accumulation).
- ❑ The flowing composition (GOR) within Region 1 is constant throughout. That means that the single phase gas entering Region 1 has the same composition as the produced well stream mixture.
- ❑ The main source of flow resistance, and thus deliverability loss in gas condensate wells. The deliverability loss depends mainly on gas relative permeability in Region 1, and the size of Region 1.
- ❑ Region 1 increases as a function of time, and its outer boundary moves gradually outward. The liquid saturation close to the wellbore first increases upon initiation of production and early depletion stages (lowering  $P_{wf}$ ) but starts to decrease later in depletion (decreasing CGR).

# Region 2

- ❑ Region 2 will always exist together with Region 1 after reservoir pressure drops below the dew point.
- ❑ Size: The size of this region depends on size of region 1 and reservoir pressure (relative to dew point pressure).
- ❑ Saturation: The saturation is approximately the same as the CVD saturation (corrected for  $S_w$ ).
- ❑ The pressure in this region is lower than the dew point pressure of the initial reservoir fluid. The oil condensing from the reservoir gas has no or negligible mobility. This region has a net accumulation of condensate.
- ❑ The deliverability loss in region 2 is usually limited as gas relative permeability is usually high (often S-shaped gas relative permeability) at low oil saturations. For well deliverability calculations, the condensate saturations in Region 2 can be approximated by the liquid dropout curve from a CVD experiment, corrected for  $S_w$ .
- ❑ The important consequence of Region 2 is that producing wellstream composition (GOR) is leaner than calculated by a simple volumetric material balance (e.g. CVD measurements).
- ❑ Region 2 has only a small effect on net condensate recovery. The effect is small on oil recovery calculations because of the relatively small difference between the producing oil-gas ratio ( $r_p=1/R_p$ ) and solution oil-gas ratio  $r_s$  of the producing wellstream (evaluated at average reservoir pressure).



**Region 3** will always and only exist when the reservoir pressure drops is above the below the dew point of the original reservoir fluid.

<b>Coexistence of Flow Regions</b>			
	$p_{wf} > p_d$	$p_R < p_d$	$p_{wf} < p_d$ and $p_R > p_d$
Region 1		X	X
Region 2		(X)	(X)
Region 3	X		X
X exist (X) may exist			

# **Proof of the Two-phase Steady-State Theory for Flow Through Porous Media (SPE14472)**

**Production from the well**



**Bottomhole pressure (BHP) falls below the saturation pressure of the reservoir fluid.**



**Condensate liquid accumulation occurs near a wellbore**



**The formation flow capacity to the gas phase becomes less than the formation flow capacity to single-phase gas flow.**

• This theory predicts saturation and pressure distribution in the vicinity of a producing well and total fluid production rate as a function of the BHP.

• It was based on the " assumption that, at any location within the two phase region the ratio of the volumetric flow rates of the two phases equals the ratio of the volume fractions of the two phases as given by constant composition expansion (CCE) at the, corresponding pressure.

**Assumptions:**

- No Dispersion,
- No Capillary,
- No Gravity effects

Component Material-Balance Equations

$$\nabla \cdot (\lambda_o x_i + \lambda_g y_i) \nabla p + q_i = \phi \frac{\partial M z_i}{\partial t}, \quad i=1 \dots n. \dots (1)$$

Overall hydrocarbon material balance

$$\nabla \cdot (\lambda_o + \lambda_g) \nabla p + q_f = \phi \frac{\partial M}{\partial t} \dots \dots \dots (2)$$

Linear system	Radial system
$(\nabla \cdot \phi) = \frac{\partial \phi}{\partial x}$	$(\nabla \cdot \phi) = \frac{1}{r} \frac{\partial}{\partial r} (r \phi_r)$
$(\nabla^2 \phi) = \frac{\partial^2 \phi}{\partial x^2}$	$(\nabla^2 \phi) = \frac{1}{r} \frac{\partial}{\partial r} (r \frac{\partial \phi}{\partial r})$

$\lambda_g$  = gas-phase mobility times density ( $k_g \rho_g / \mu_g$ )  
 $\lambda_o$  = oil-phase mobility times density ( $k_o \rho_o / \mu_o$ )  
 $\bar{M}$  = overall hydrocarbon quantity ( $\rho_o S_o + \rho_g S_g$ )

Concept of Steady State: At steady state, there is no accumulation of component "i" at any location in the reservoir and no accumulation of overall mass of hydrocarbon.

$$\frac{\partial M z_i}{\partial t} = 0, \quad i=1 \dots n, \dots \dots \dots (3)$$

$$\frac{\partial M}{\partial t} = 0. \dots \dots \dots (4)$$

There is no component molar production except at the producing well.

$$\nabla \cdot (\lambda_o x_i + \lambda_g y_i) \nabla p + q_i = \phi \frac{\partial M z_i}{\partial t}, \quad i=1 \dots n. \dots (1) \xrightarrow{\frac{\partial M z_i}{\partial t} = 0, \quad i=1 \dots n,} \nabla \cdot (\lambda_o x_i + \lambda_g y_i) \nabla p = 0. \dots (5)$$

$\vec{C}_i$  is the molar flux of Component  $i$

$$(\lambda_o x_i + \lambda_g y_i) \nabla p = \vec{C}_i. \dots (6)$$

$$\nabla \cdot (\lambda_o + \lambda_g) \nabla p + q_f = \phi \frac{\partial M}{\partial t}. \dots (2) \xrightarrow{\frac{\partial M}{\partial t} = 0.} \nabla \cdot (\lambda_o + \lambda_g) \nabla p = 0. \dots (7)$$

$\vec{C}_o$  is the overall molar flux

$$(\lambda_o + \lambda_g) \nabla p = \vec{C}_o, \dots (8)$$

By taking the dot products of Eqs. 6 and 8 with a unit vector and then dividing the molar flux of Component  $i$ ,  $|C_i|$ , by the overall molar flux,  $|C_o|$ , we obtain

$$\frac{\lambda_o x_i + \lambda_g y_i}{\lambda_o + \lambda_g} = C_{io}. \dots (9)$$

$$z_{if} = \frac{\lambda_o x_i + \lambda_g y_i}{\lambda_o + \lambda_g} = C_{io}. \dots (10)$$

$C_{oi}$  = overall flowing composition for Component  $i$

The **overall flowing composition** reflects what the composition would be if one were to sample the flow streams in the reservoir.

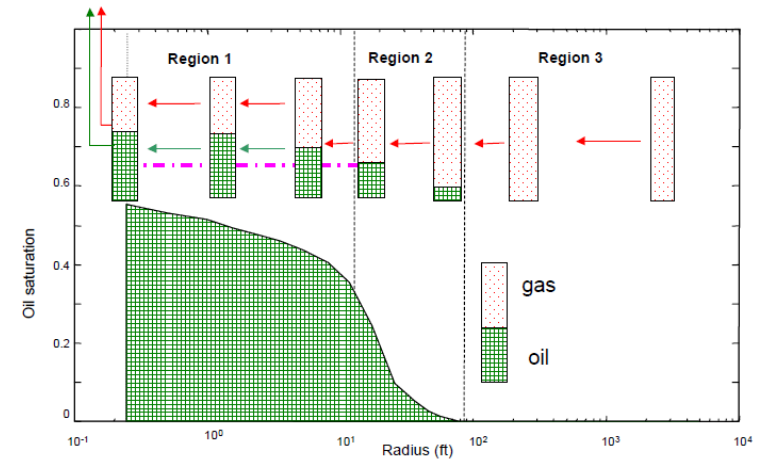
$$z_{if} = \frac{\lambda_o x_i + \lambda_g y_i}{\lambda_o + \lambda_g} = C_{io} \dots \dots \dots (10)$$

The overall **in-place composition** is defined as

$$z_i = \frac{\rho_o S_o x_i + \rho_g S_g y_i}{\rho_o S_o + \rho_g S_g} \dots \dots \dots (11)$$

The **overall in-place composition** at a given location would be obtained if one were to analyze the core at that location in the reservoir.

We assumed that the upstream end of the system (pressure greater than the saturation pressure) is in the single-phase region. Because no composition variations take place in the single-phase region, the fluid flowing in the single-phase region has the same composition as the in-place reservoir fluid composition before depletion. Eq. 10 implies that the steady-state overall flowing composition of any component is constant with respect to distance. Therefore, the steady-state overall flowing composition,  $z_{if}$ , in the two-phase region is also the same as the overall original reservoir fluid composition,  $z_{io}$ :



$$z_{if} = z_{io} \dots \dots \dots (12)$$

**The Proof of  $q_o/q_g = V_o/V_g$ .** A common engineering assumption is that the in-place gas and liquid phases are in equilibrium in the reservoir. According to the phase equilibrium concepts, the flowing fluid must be in equilibrium because it is derived from the equilibrium in-place gas and liquid phases. The CCE equation for the flowing fluid in equilibrium can be written with Eq. 10.

$$z_{if} = L_f x_i + (1 - L_f) y_i \quad \dots \dots \dots (14)$$

where

$$L_f = \frac{\lambda_o}{\lambda_o + \lambda_g} \quad \dots \dots \dots (15)$$

or

$$1 - L_f = \frac{\lambda_g}{\lambda_o + \lambda_g} \quad \dots \dots \dots (16)$$

The CCE equation for the original reservoir fluid in equilibrium can be written as

$$z_{io} = L_{CCE} x_{io} + (1 - L_{CCE}) y_{io} \quad \dots \dots \dots (17)$$

Because the overall flowing composition at steady state equals the original reservoir fluid composition (Eq. 12), the liquid- and gas-phase compositions of the flowing fluid equal the liquid- and gas-phase compositions of the original reservoir fluid, respectively, if both fluids are flashed at the same pressure and temperature:

$$x_i = x_{io} \quad \dots \dots \dots (18)$$

and

$$y_i = y_{io} \quad \dots \dots \dots (19)$$

$L_{CCE}$  = mole fraction of the liquid phase in a constant composition expansion of the original fluid, in./(in.-°F) [m/(m·K)]

$x_i$  = in-place mole fraction of Component  $i$  in the liquid (oil) phase

$x_{io}$  = liquid-phase mole fraction of Component  $i$  in a constant-composition expansion of the original fluid

Substitution of Eqs. 15, 16, 18, and 19 into Eq. 14 and derivation to Eq. 17 by virtue of Eq. 12 yields

$$\frac{\lambda_o}{(\lambda_o + \lambda_g)} x_{io} + \frac{\lambda_g}{(\lambda_o + \lambda_g)} y_{io} = L_{CCE} x_{io} + (1 - L_{CCE}) y_{io}, \quad (20)$$

and by rearrangement,

$$\left( \frac{\lambda_o}{\lambda_o + \lambda_g} - L_{CCE} \right) x_{io} + \left[ \frac{\lambda_g}{\lambda_o + \lambda_g} - (1 - L_{CCE}) \right] y_{io} = 0. \quad (21)$$

Because  $x_{io}$  and  $y_{io}$  are not equal except at the critical point, it follows that

$$\frac{\lambda_o}{\lambda_o + \lambda_g} = L_{CCE} \quad (22)$$

or

$$\frac{\lambda_g}{\lambda_g + \lambda_o} = 1 - L_{CCE}. \quad (23)$$

Dividing Eq. 22 by Eq. 23 gives

$$\frac{\lambda_o}{\lambda_g} = \frac{L_{CCE}}{1 - L_{CCE}}. \quad (24)$$

The phase mobilities are

$$\lambda_o = \frac{k_o \rho_o}{\mu_o} \Big|_{x_i} \quad (25)$$

and

$$\lambda_g = \frac{k_g \rho_g}{\mu_g} \Big|_{y_i}, \quad (26)$$

where compositions below the vertical bars signify compositions at which densities and viscosities are evaluated. By definition,

$$L_{CCE} = V_o \rho_o \Big|_{x_{io}} \quad (27)$$

and

$$1 - L_{CCE} = V_g \rho_g \Big|_{y_{io}}, \quad (28)$$

where  $V_o$  and  $V_g$  are the volume fractions of the liquid and gas phases, respectively, during CCE of the original reservoir fluid. Because  $x_i = x_{io}$  and  $y_i = y_{io}$  at steady state,

$$\rho_o \Big|_{x_i} = \rho_o \Big|_{x_{io}}, \dots\dots\dots(29a)$$

$$\rho_g \Big|_{y_i} = \rho_g \Big|_{y_{io}}, \dots\dots\dots(29b)$$

$$\mu_o \Big|_{x_i} = \mu_o \Big|_{x_{io}}, \dots\dots\dots(29c)$$

and

$$\mu_g \Big|_{y_i} = \mu_g \Big|_{y_{io}}, \dots\dots\dots(29d)$$

Substitution of Eqs. 29a through 29d into Eqs. 24 through 28 yields

$$\frac{\left(\frac{k_o}{\mu_o}\right)}{\left(\frac{k_g}{\mu_g}\right)} = \frac{V_o}{V_g} \dots\dots\dots(30)$$

or

$$\frac{q_o}{q_g} = \frac{V_o}{V_g} \dots\dots\dots(31)$$

The variables  $q_o$  and  $q_g$  are the molar reservoir flow rates of liquid and gas phases, respectively. These rates are also equivalent to the reservoir flow rates expressed in terms of surface units.

## Nomenclature

- $C$  = number of components
- $\vec{C}_i$  = molar flux of Component  $i$
- $C_o$  = overall molar flux
- $C_{oi}$  = overall flowing composition for Component  $i$
- $C$  = number of components
- $F$  = degrees of freedom
- $k_g$  = effective permeability to gas, md
- $k_o$  = effective permeability to oil, md
- $L_{CCE}$  = mole fraction of the liquid phase in a constant composition expansion of the original fluid, in./(in.-°F) [m/(m·K)]
- $L_f$  = defined by Eq. 15
- $M$  = overall hydrocarbon quantity ( $\rho_o S_o + \rho_g S_g$ )
- $n$  = variable for number of components
- $p$  = pressure, psi [kPa]
- $p_d$  = pressure at dewpoint
- $p_e$  = external pressure
- $p_{wf}$  = flowing BHP
- $P$  = number of phases
- $q_f$  = overall hydrocarbon molar production rate per unit volume, lbm mol/sec-ft<sup>3</sup> [kmol/s·m<sup>3</sup>]
- $q_g$  = reservoir flow rate of gas phase expressed in terms of surface units, Mcf/D [m<sup>3</sup>/d]
- $q_i$  = molar injection rate per unit volume of Component  $i$ , lbm mol/sec-ft<sup>3</sup> [kmol/s·m<sup>3</sup>]
- $q_o$  = reservoir flow rates of liquid phase expressed in terms of surface units, ft<sup>3</sup>/(sec-ft<sup>2</sup>) [kg/s·m<sup>2</sup>]



$S_g$  = gas-phase saturation  
 $S_o$  = oil-phase saturation  
 $V_g$  = volume fraction of the gas phase in a constant-composition expansion  
 $V_o$  = volume fraction of the liquid phase in a constant-composition expansion  
 $x$  = mole fraction  
 $x_e$  = length of external boundary, ft [m]  
 $x_i$  = in-place mole fraction of Component  $i$  in the liquid (oil) phase  
 $x_{io}$  = liquid-phase mole fraction of Component  $i$  in a constant-composition expansion of the original fluid  
 $x_t$  = length of the two-phase region, ft [m]  
 $y_i$  = in-place mole fraction of Component  $i$  in the gas phase  
 $y_{io}$  = gas-phase mole fraction of Component  $i$  in a constant-composition expansion of the original fluid  
 $z_i$  = overall in-place mole fraction of Component  $i$   
 $z_{if}$  = overall flowing mole fraction of Component  $i$   
 $z_{io}$  = overall mole fraction of Component  $i$  in the original fluid  
 $\lambda_g$  = gas-phase mobility times density ( $k_g \rho_g / \mu_g$ )  
 $\lambda_o$  = oil-phase mobility times density ( $k_o \rho_o / \mu_o$ )  
 $\mu_g$  = gas-phase viscosity, cp [Pa·s]  
 $\mu_o$  = oil-phase viscosity, cp [Pa·s]  
 $\rho_g$  = gas-phase density, lbm mol/ft<sup>3</sup> [kmol/m<sup>3</sup>]  
 $\rho_o$  = oil-phase density, lbm mol/ft<sup>3</sup> [kmol/m<sup>3</sup>]

$\phi$  = porosity  
 $\nabla$  = gradient operator  
 $\nabla \cdot$  = divergence operator

### Subscripts

$g$  = gas phase  
 $i$  = Component  $i$   
 $o$  = oil phase

**Compositional Model Results.** Results computed with the analytical equations derived in this paper were compared with the results for the same system obtained with a compositional model.<sup>4</sup> The compositional-model simulations were carried out for a linear gas-condensate system (Fig. 1) until steady state was achieved. A constant-pressure boundary was maintained by use of an injection well with a BHP of 6,000 psia [41.4 MPa]. The composition of the injected fluid was the original reservoir-fluid composition. The producing BHP was 1,000 psia [6.9 MPa] in these simulations. Fifty grid points of uniform spacing were selected for this system. The model predictions indicated that steady state was achieved within 1 day. An 11-component fluid system was used for all the simulations.

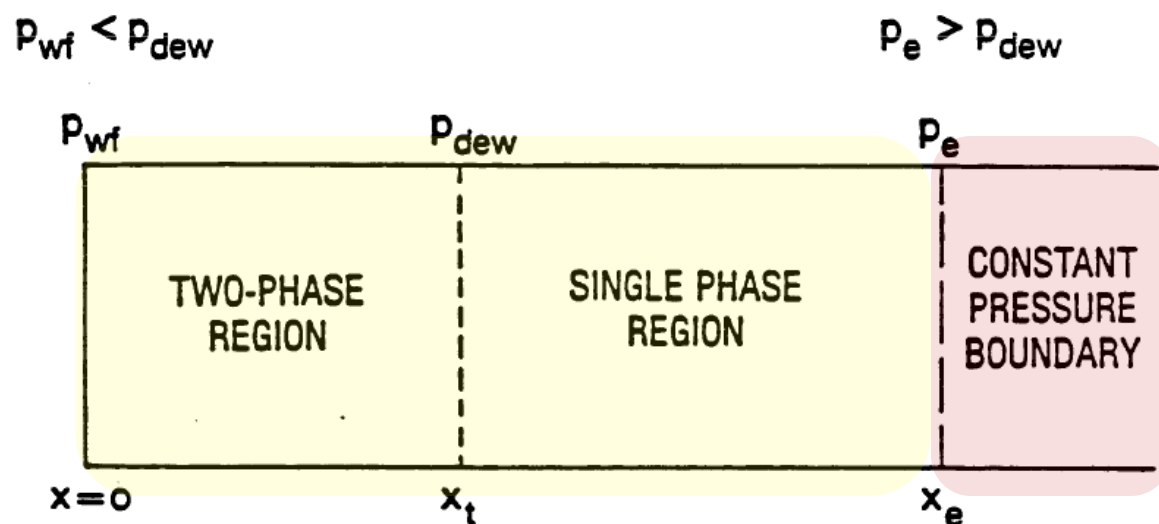


Figure 1. Linear System for Compositional Model Studies

The overall steady-state flowing composition in the model is identical to the original reservoir-fluid composition (Figs. 2 and 3). This result is consistent with the analytical result (Eq. 12). The equilibrium  $K$ -value of Component  $i$  is defined as the ratio of the mole fraction of the component in the gas phase ( $y_i$ ) to the ratio of the mole fraction of the component in the liquid phase ( $x_i$ ).

$$z_{if} = \frac{\lambda_o x_i + \lambda_g y_i}{\lambda_o + \lambda_g} = C_3 \text{ (a constant)}$$

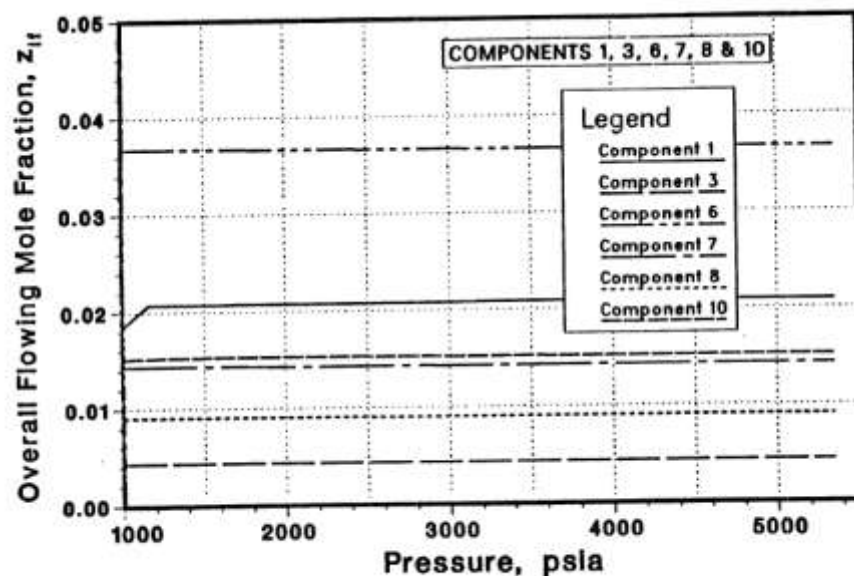


Figure 2. Overall Flowing Mole Fraction in the Reservoir

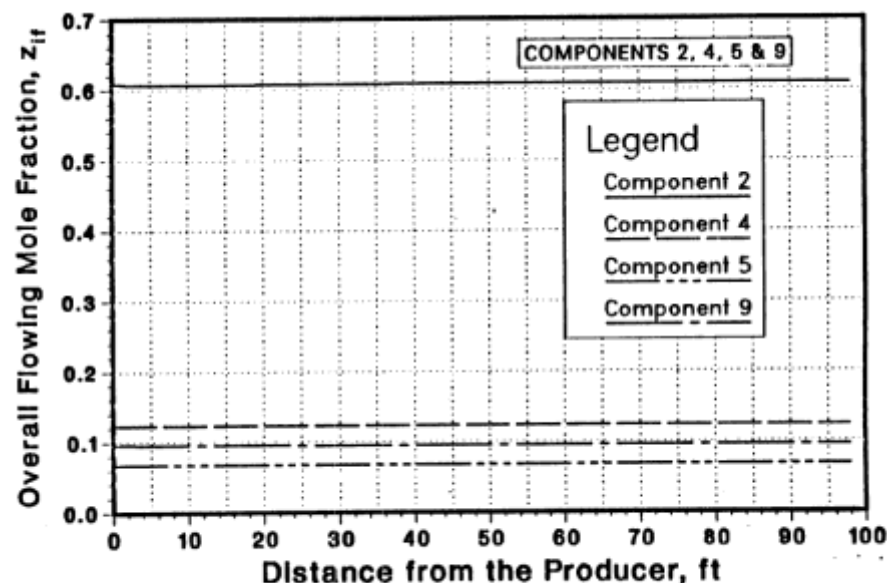


Figure 3. Overall Flowing Mole Fraction in the Reservoir

The equilibrium  $K$ -values of the flowing fluid at steady state are the same as that of the original reservoir fluid by virtue of Eq. 12. Because the equilibrium  $K$ -values of the flowing fluid are the same as the equilibrium  $K$ -values of the in-place fluid in the context of phase equilibrium constraints, the equilibrium  $K$ -values of the in-place fluid at steady state must equal the equilibrium  $K$ -values of the original reservoir fluid before depletion. The overall in-place composition in the two-phase region (Eq. 11), however, will be different from the original reservoir fluid composition. The equilibrium  $K$ -values for the original reservoir fluid were obtained during CCE with an equation of state (EOS). The compositional model simulations described earlier provided the liquid- and gas-phase compositions used to calculate the equilibrium  $K$ -values of the in-place fluid at steady state. The equilibrium  $K$ -values predicted by the compositional model are in excellent agreement with those obtained by the EOS during CCE (Figs. 4 through 6).

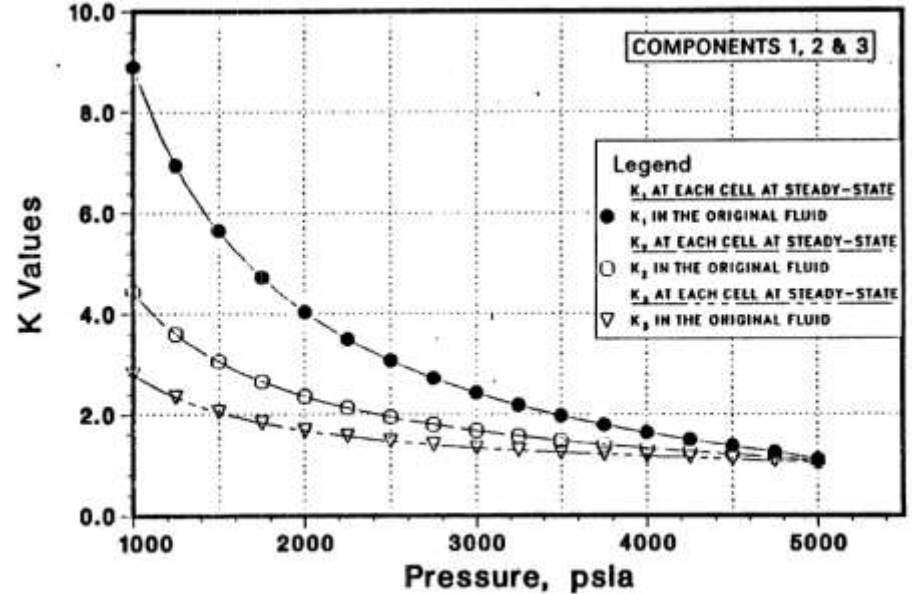


Figure 4. Comparison of K Values

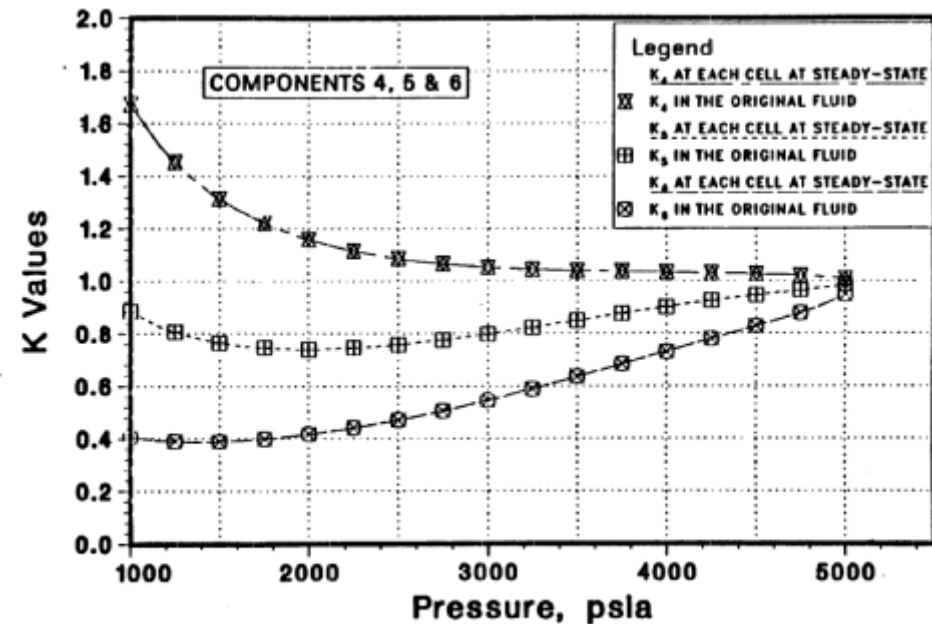


Figure 5. Comparison of K Values

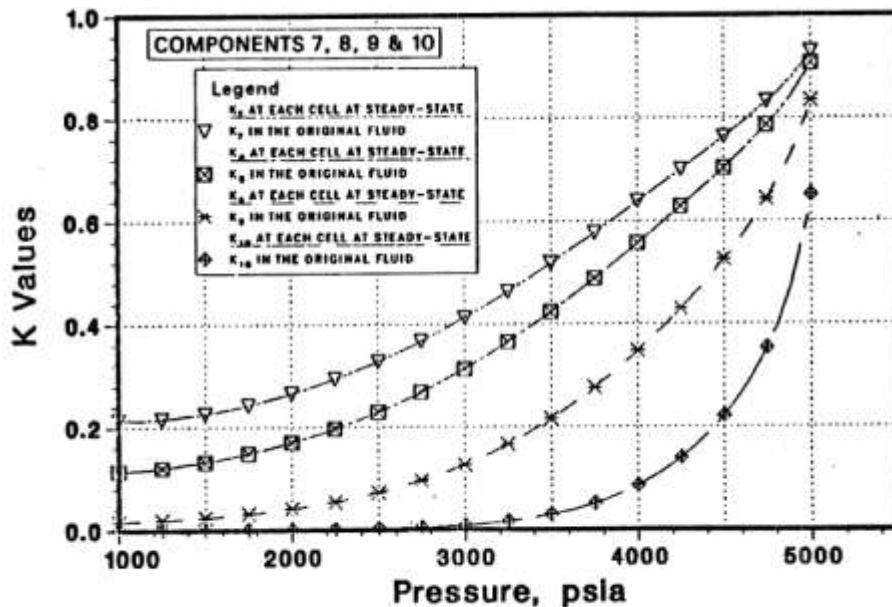


Figure 6. Comparison of K Values

The compositional model simulations also show excellent agreement between the model-calculated  $q_o/q_g$  at steady state and the EOS-predicted  $V_o/V_g$  of the original reservoir fluid (Fig. 7).

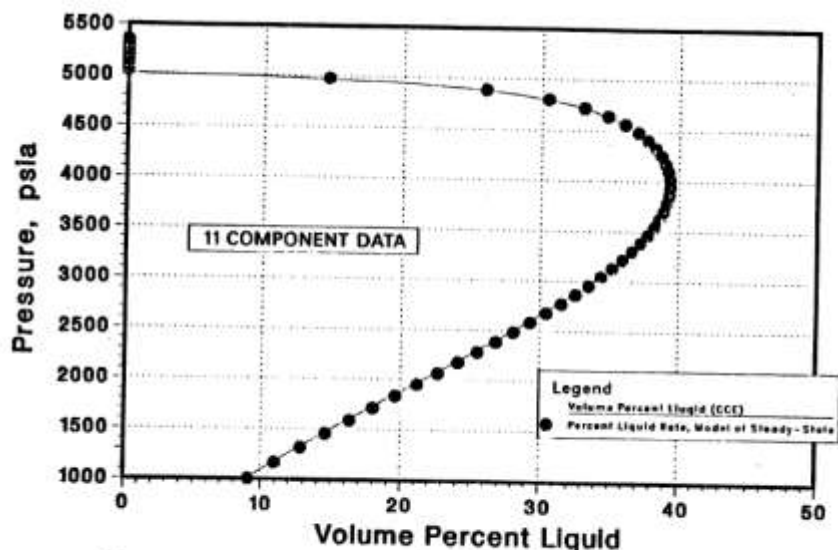


Figure 7. Comparison of Volume Percent Liquid (CCE) vs. Percent Liquid Rate (Model)

The in-place composition profile at steady state was calculated with the analytical procedure outlined in the previous section. The comparison of the calculated composition profile using this procedure with the steady-state composition profile predicted by the compositional model shows excellent agreement. A comparison for Component 2 (methane) is displayed in Fig. 8. Similar comparisons for other components yielded excellent agreements.

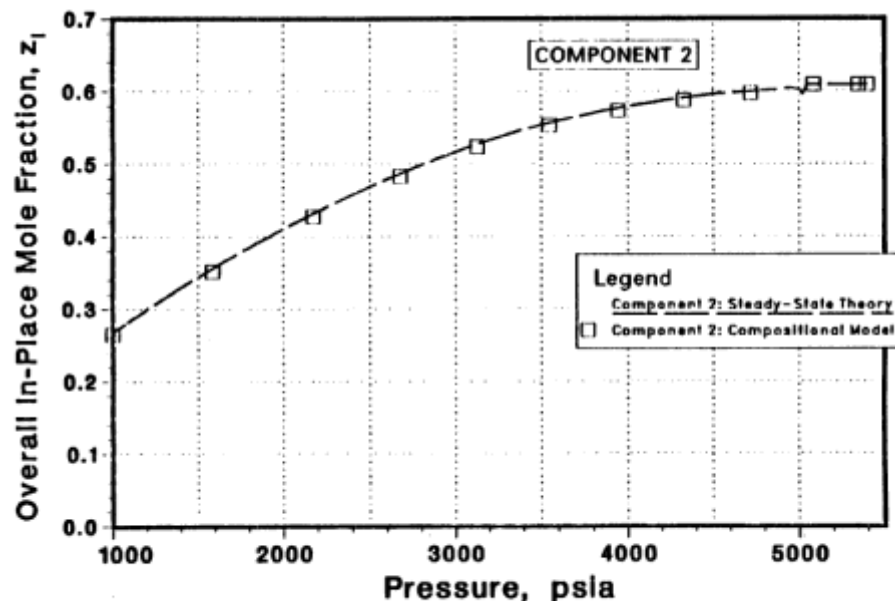


Figure 8. Overall In-Place Mole Fraction In the Reservoir

**Usefulness of the Results for Two-Phase Pressure Transient Analysis.** One of the most difficult tasks in the analysis of two-phase pressure transient data is the determination of in-situ saturations as a function of pressure. It is not expected that the saturation profiles predicted by the two-phase steady-state theory will be followed during unsteady flows. As a first approximation, however, one can use the concepts presented in this paper to evaluate a pseudopressure function<sup>2</sup> to analyze the two-phase pressure transient data.

# $k_{rg}/k_{ro}$

**Modified Black Oil PVT**  $\frac{k_{rg}}{k_{ro}} = \frac{1 - r_{vF} R_s}{r_{vF} - r_v} \frac{\mu_g B_g}{\mu_o B_o}$

$$\frac{k_{rg}}{k_{ro}}(p) = \left( \frac{R_p - R_s}{1 - r_s R_p} \right) \frac{\mu_g B_{gd}}{\mu_o B_o}$$

Thermodynamic  
property

Fluid flow property

## Compositional Model

$$\frac{k_{rg}}{k_{ro}}(p) = \left( \frac{1}{V_{roCCE}} - 1 \right) \frac{\mu_g}{\mu_o}$$

$$V_{roCCE} = V_o / (V_g + V_o)$$

$B_{gd}$  : dry gas formation volume factor, rb/scf

$R_p$  : Producing gas oil ratio, scf/stb

$R_s$  : Solution gas oil ratio, scf/stb

$r_s$  : Solution oil gas ratio, stb/scf

$V_{roCCE}$  : Relative oil volume in CCE experiment for each pressure step

$V_o$  : Oil volume in an experimental cell in each pressure step, ft<sup>3</sup>

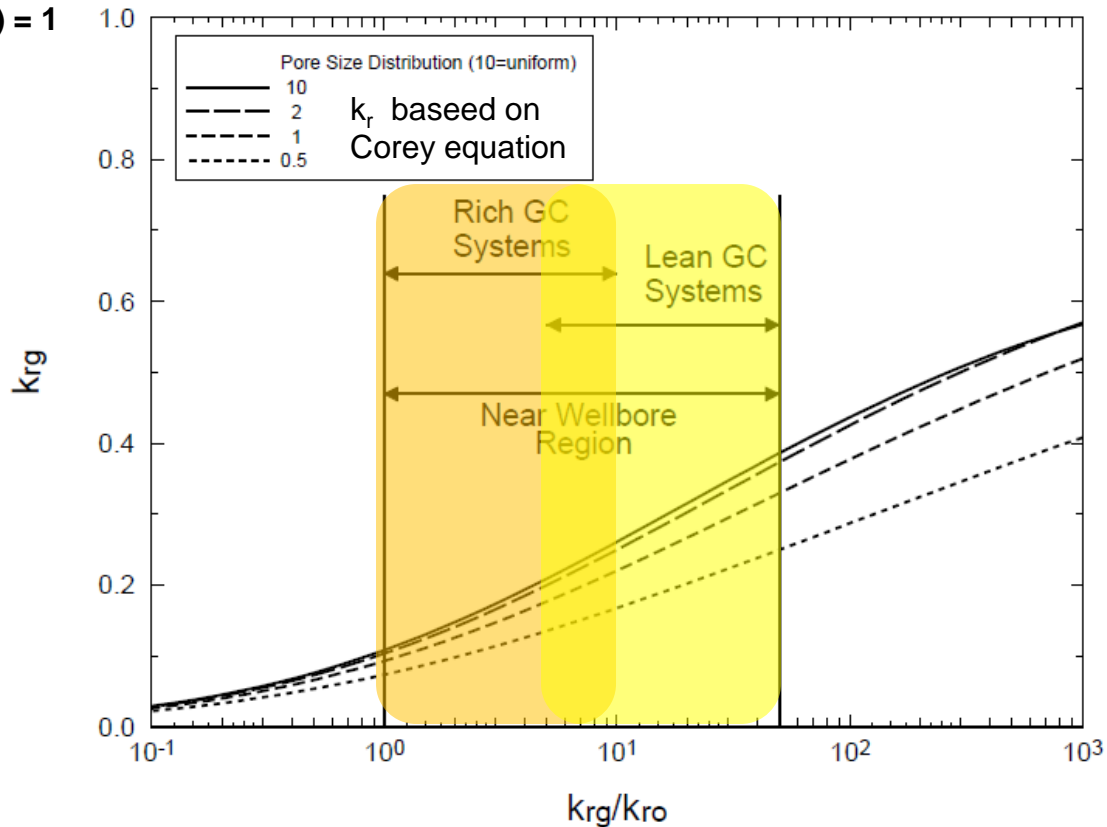
$V_g$  : Gas volume in an experimental cell in each pressure step, ft<sup>3</sup>

$$\frac{k_{rg}}{k_{ro}}(p) = \left( \frac{R_p - R_s}{1 - r_s R_p} \right) \frac{\mu_g B_{gd}}{\mu_o B_o}$$

so

$$k_{rg}(p) = f(k_{rg}/k_{ro}(p))$$

$k_{rg}(S_{wi}) = 1$



$B_{gd}$  :dry gas formation volume factor, rb/scf

$R_s$  : Solution gas oil ratio, scf/stb

$V_{roCCE}$  :Relative oil volume in CCE experiment for each pressure step

$V_o$  : Oil volume in an experimental cell in each pressure step, ft<sup>3</sup>

$V_g$  : Gas volume in an experimental cell in each pressure step, ft<sup>3</sup>

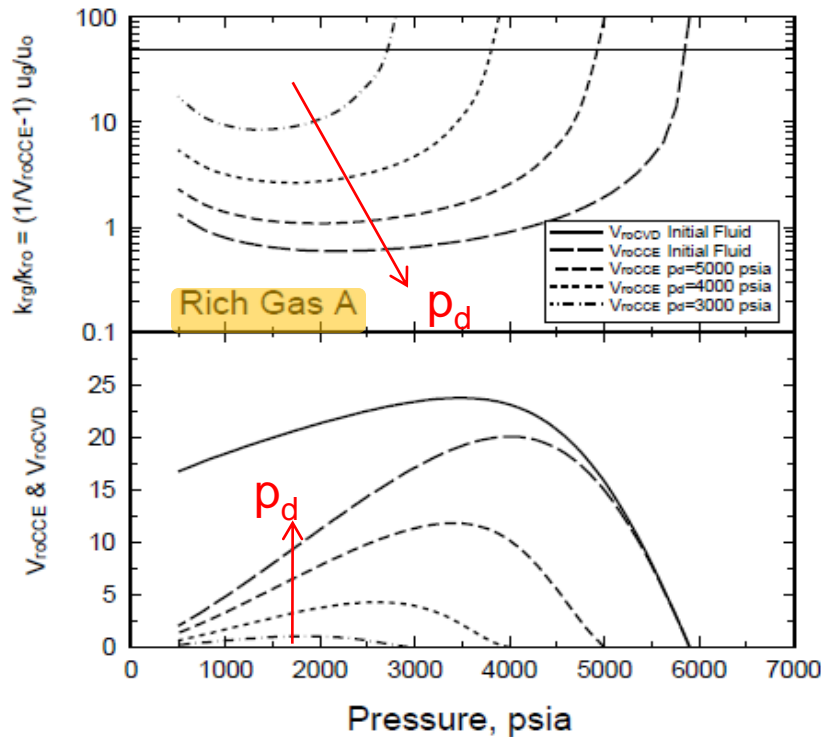
$R_p$  : Producing gas oil ratio, scf/stb

$r_s$  : Solution oil gas ratio, stb/scf

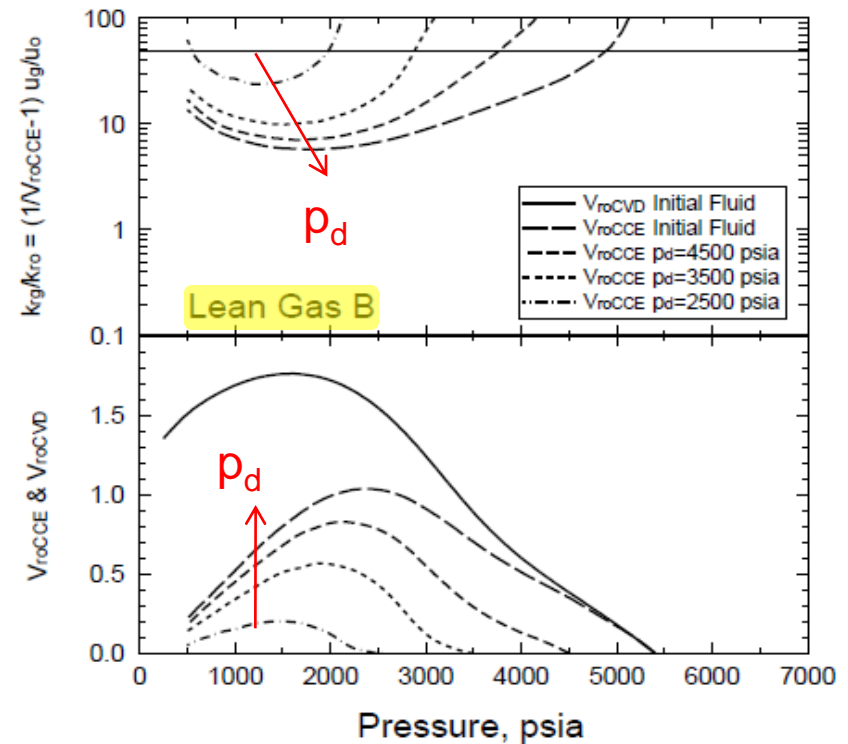


- $k_{rg}$  and  $k_{ro}$  can each be expressed directly as a function of the ratio  $k_{rg}/k_{ro}$  when both phases are mobile. (Evinger and Muskat).

- If the ratio of  $k_{rg}/k_{ro}$  is known, the values of  $k_{rg}$  and  $k_{ro}$  can be calculated from the relative permeability curves, and the pseudo-pressure integral evaluated.



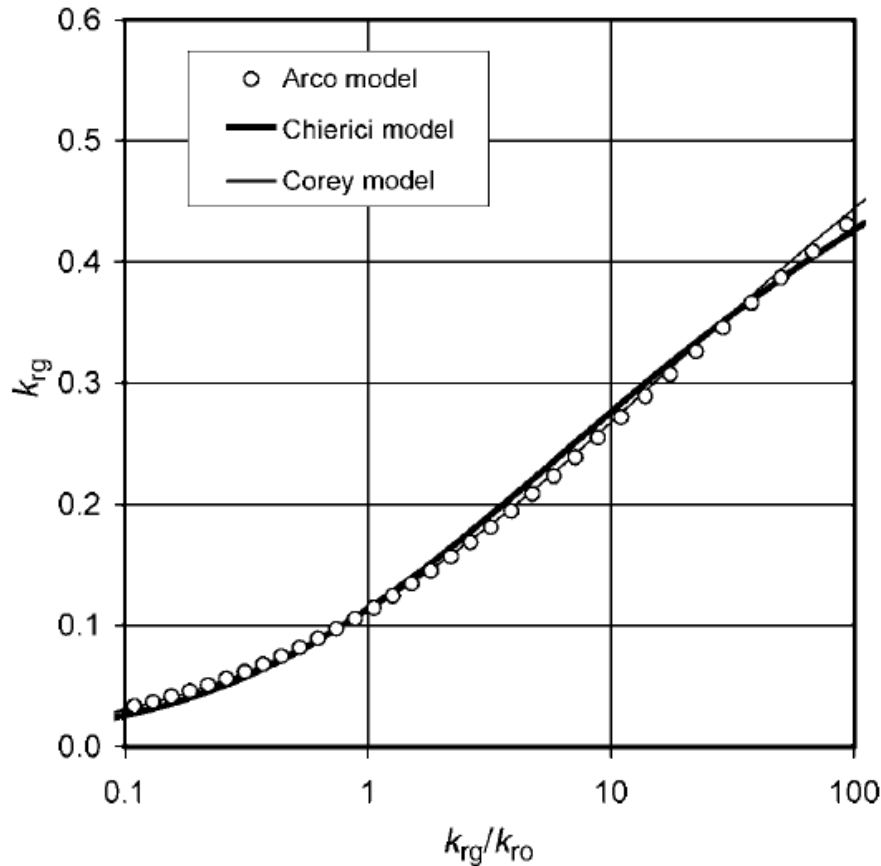
(Fevang, 1995)



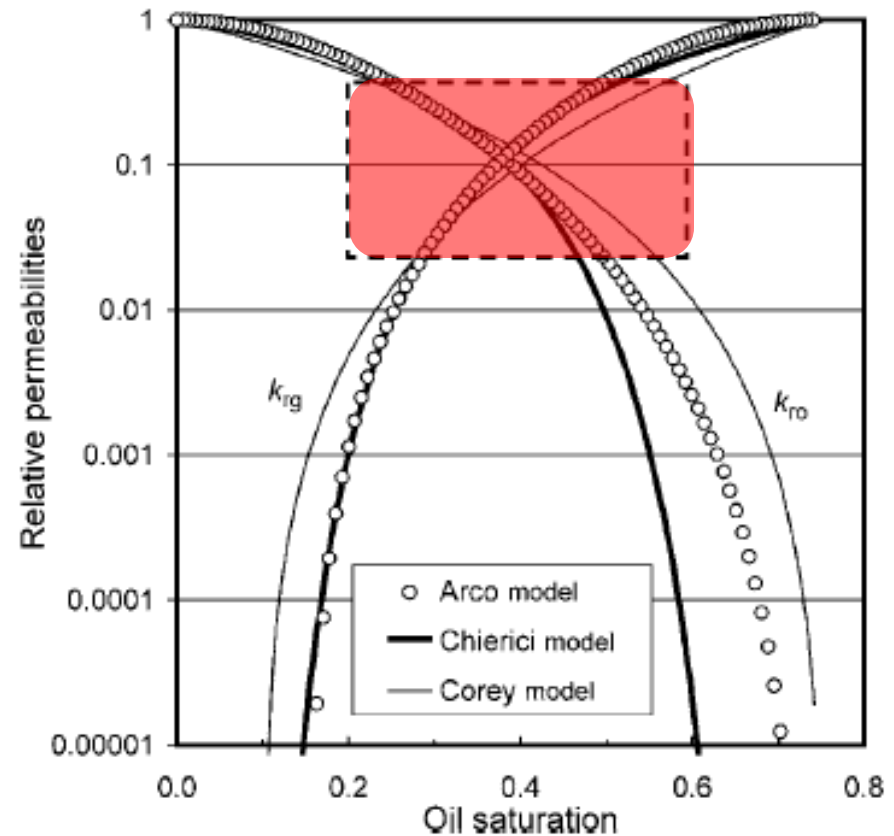
Diagnostic plots for Rich Gas A and Lean Gas B showing the variation of  $k_{rg}/k_{ro}$  (in Region 1) and CCE oil relative volume as a function of pressure during depletion.



$K_{rg}(k_{rg}/k_{ro})$  is the fundamental relationship controlling the reduction in gas relative permeability in the near well bore region.



(Whitson et al., 2003)



Saturation dependent relative permeability curves for three different immiscible correlations, showing in particular the region that affect flow behavior in the near-well region (boxed area). The three correlations have the 'same'  $k_{rg} = f(k_{rg}/k_{ro})$  relationship in the boxed region.

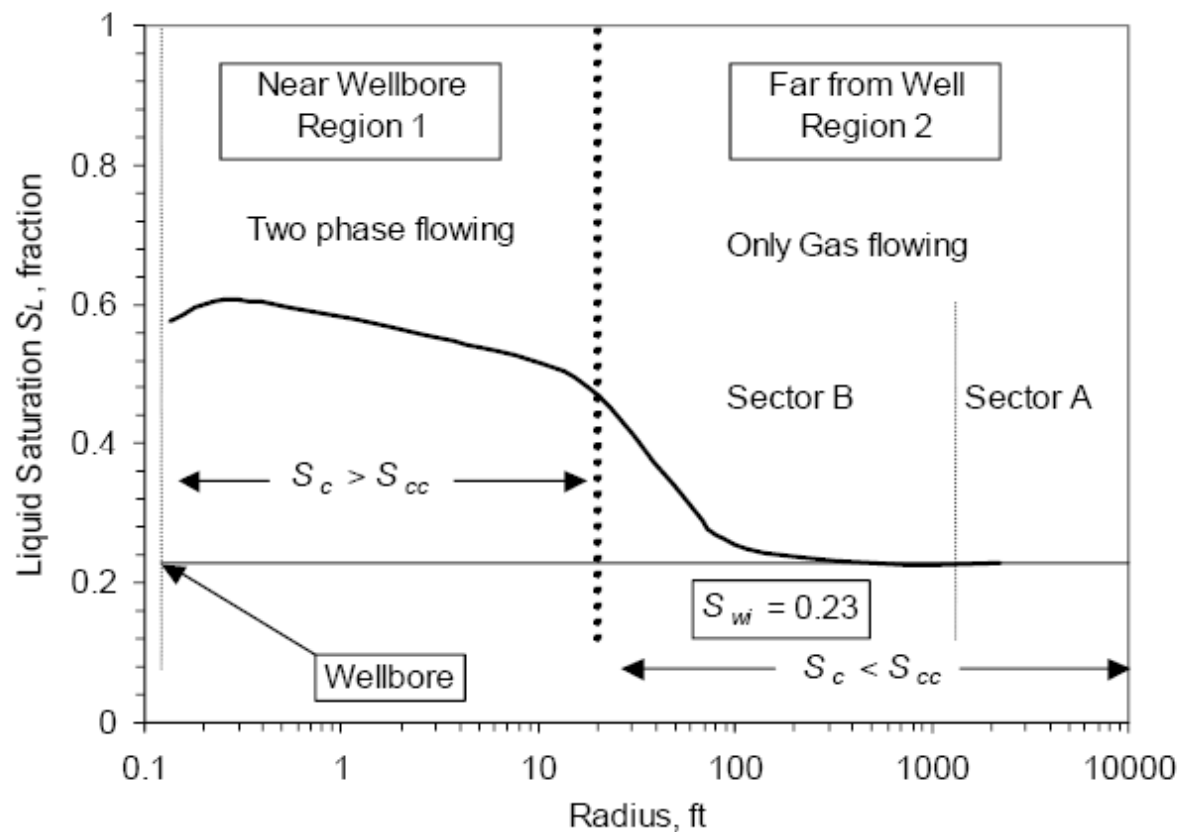


Fig. 2.1 - Flow regions in gas condensate reservoir producing by depletion after Zapata<sup>24</sup>

# Capillary Number

- Most gas-condensate reservoirs are found at near-critical conditions where the interfacial tension between gas and condensate is low.
- Experimental studies have shown that as interfacial tensions (IFT) decrease, the relative permeability curves become progressively straighter (miscible) whereas the residual fluid saturations decrease.
- An increase in relative permeability with velocity has been demonstrated in numerous laboratory core-flood experiments and actual field data. Danesh et al were the first to report laboratory experiments results showing improvements of relative permeability in condensate systems with increases in velocity or decreases in interfacial tension.
- High velocities and low IFT's both increase the ratio of viscous to capillary forces and can be represented by a single parameter, called the capillary number ( $N_c$ )
- A combination of IFT and velocity is called Capillary Number. 
$$N_c = \frac{\mu_g v}{\sigma}$$

# Effect of IFT & Rate on Darcy $K_r$

Until 1995 it was assumed that relative permeability of a fluid is mainly a function of:

$$k_r = f \left\{ \begin{array}{l} \textit{Pore size distribution} \\ \textit{Wettability} \\ \textit{Saturation} \\ \textit{Saturation history} \\ \textit{IFT} \end{array} \right.$$

In 1995 both Shell and Heriot-Watt (Henderson) published results showing the effect of capillary number ( $N_c$ ) on relative permeability.

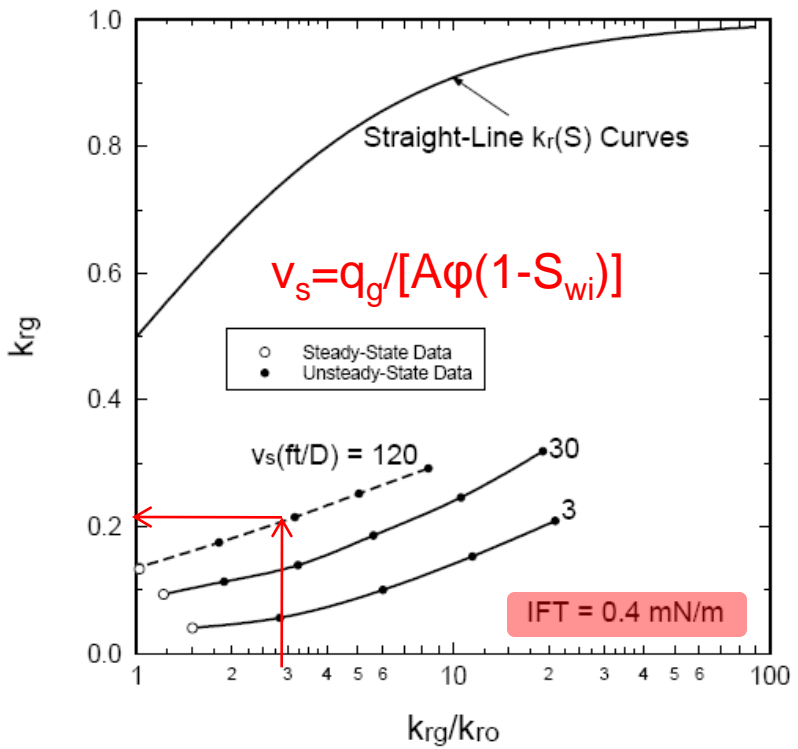
$$N_c = \frac{\mu_g v}{\sigma}$$

- Capillary number describes the relative balance of viscous and capillary forces

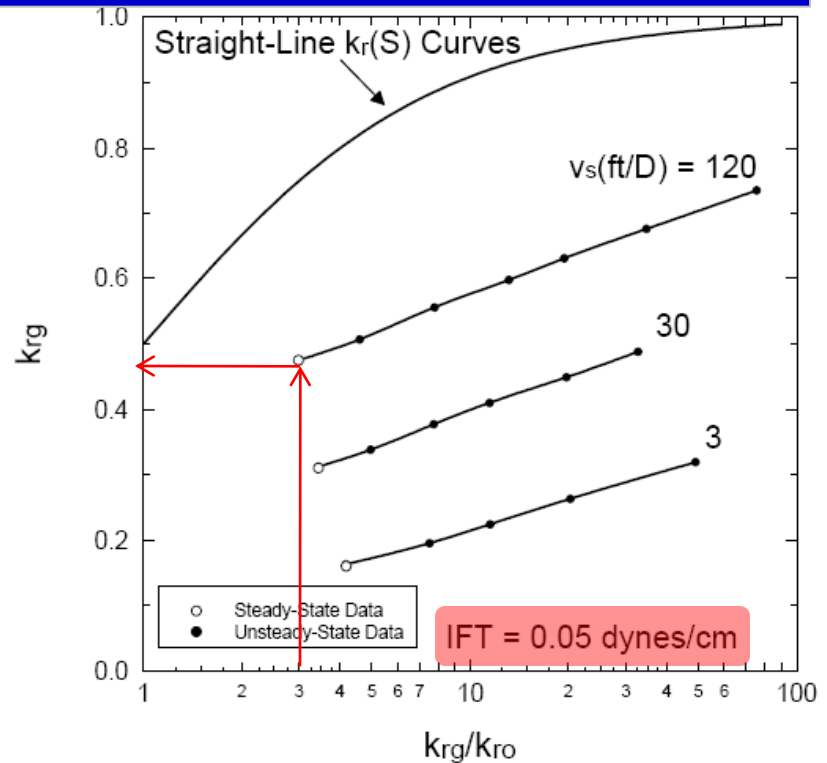
$$(N_c = \Delta p_{\text{viscous}}/P_c, \text{ or } N_c = v_{pg}\mu_g/\sigma_{go})$$

- For small  $N_c$ , capillary forces dominate and traditional ('immiscible') relative permeability behavior is found.
- For large  $N_c$ , viscous forces dominate and relative permeabilities tend to approach straight lines or 'misciblelike' behavior.
- IFT change the shape of the curve
- $v_s$  shifts the curve to higher  $k_{rg}$

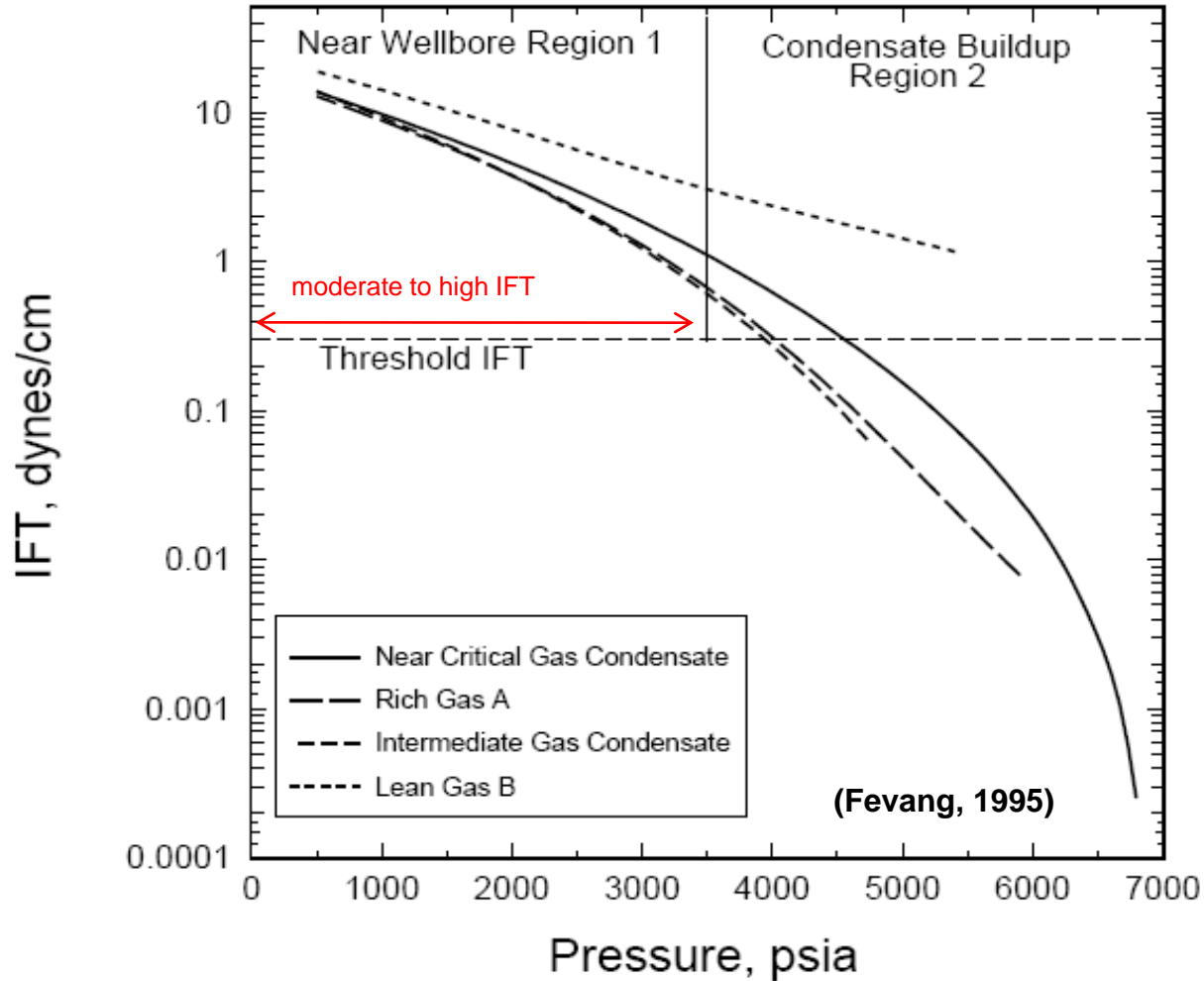
Velocity effect on  $k_{rg} = f(k_{rg}/k_{ro})$  relationship for a Berea sandstone and a synthetic gas condensate mixture Data taken from Henderson et al.



Fevang, 1995

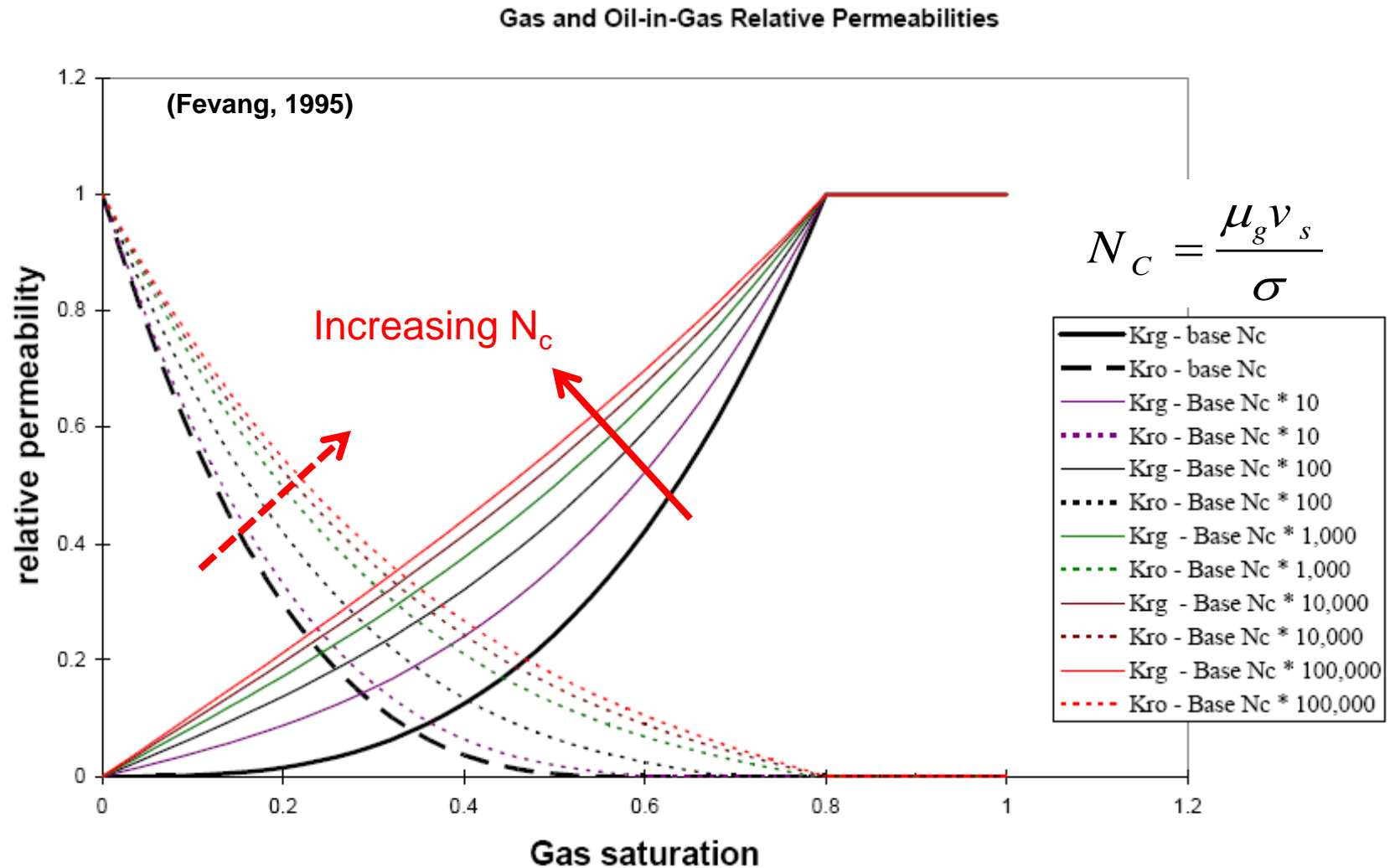


## Interfacial Tension as a Function of Pressure for Different Gas Condensates



# Miscible and Immiscible $K_r$

As IFT approaches zero the relative permeabilities approach straight lines with zero residual saturations



# Whitson and Fevang (1997)

$$k_{rg} = f_I \cdot k_{rgI} + (1 - f_I) \cdot k_{rgM}$$

$$k_{rgM} = k_{rg}^o \cdot \frac{1}{1 + (k_{rg}/k_{ro})^{-1}}$$

Transition function  $f_I = \frac{1}{(\alpha \cdot N_c)^n + 1}$

$\alpha$  is a constant dependent only on rock properties  $\alpha = \frac{2 \cdot 10^4}{\sqrt{k\phi}}, \quad n = 0.7$

$k_{rg}^o$  gas relative permeability at  $S_{wi}$

$k_{rgI}$  and  $k_{rgM}$  are evaluated at the same value of  $k_{rg}/k_{ro}$  – not at the same saturation.

It only can be used for the steady-state region where both gas and oil are flowing.



# Effect of Non-Darcy Flow on $K_r$

In near the wellbore region where the velocity is highest, any positive effect that high  $N_c$  has on "Darcy" relative permeability may be reduced by non-Darcy flow effects.

## Non-Darcy Flow: Forchheimer equation

To quantify the effect of non-Darcy pressure loss, an effective gas relative permeability  $k_{rg,eff}$  is defined.

$$\boxed{-\frac{\partial P}{\partial x} = \frac{\mu}{k} V + \beta \rho V^2} \quad \longrightarrow \quad -\frac{\partial P}{\partial x} = \frac{\mu}{k_{HVF}} V$$

$$\beta = a k^b \phi^c \quad a \sim 10^9 - 10^{10}, \quad b \sim 0.5 - 1.5, \quad \text{and} \quad c \sim 0 - 5.5.$$

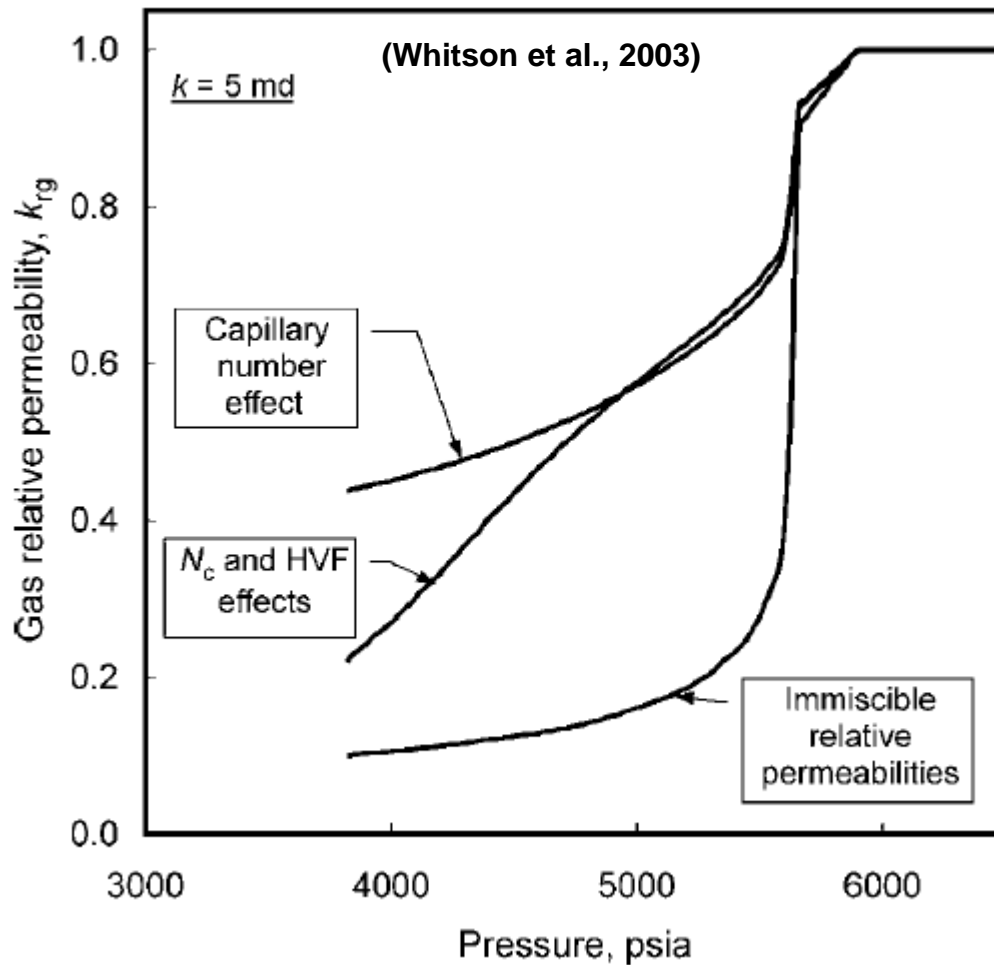
The correction of  $\beta$  for relative permeability effect (Blom and Hagoort ;2003b)

$$\beta_{eff} = \beta \cdot k_{rg}^{-b'}$$

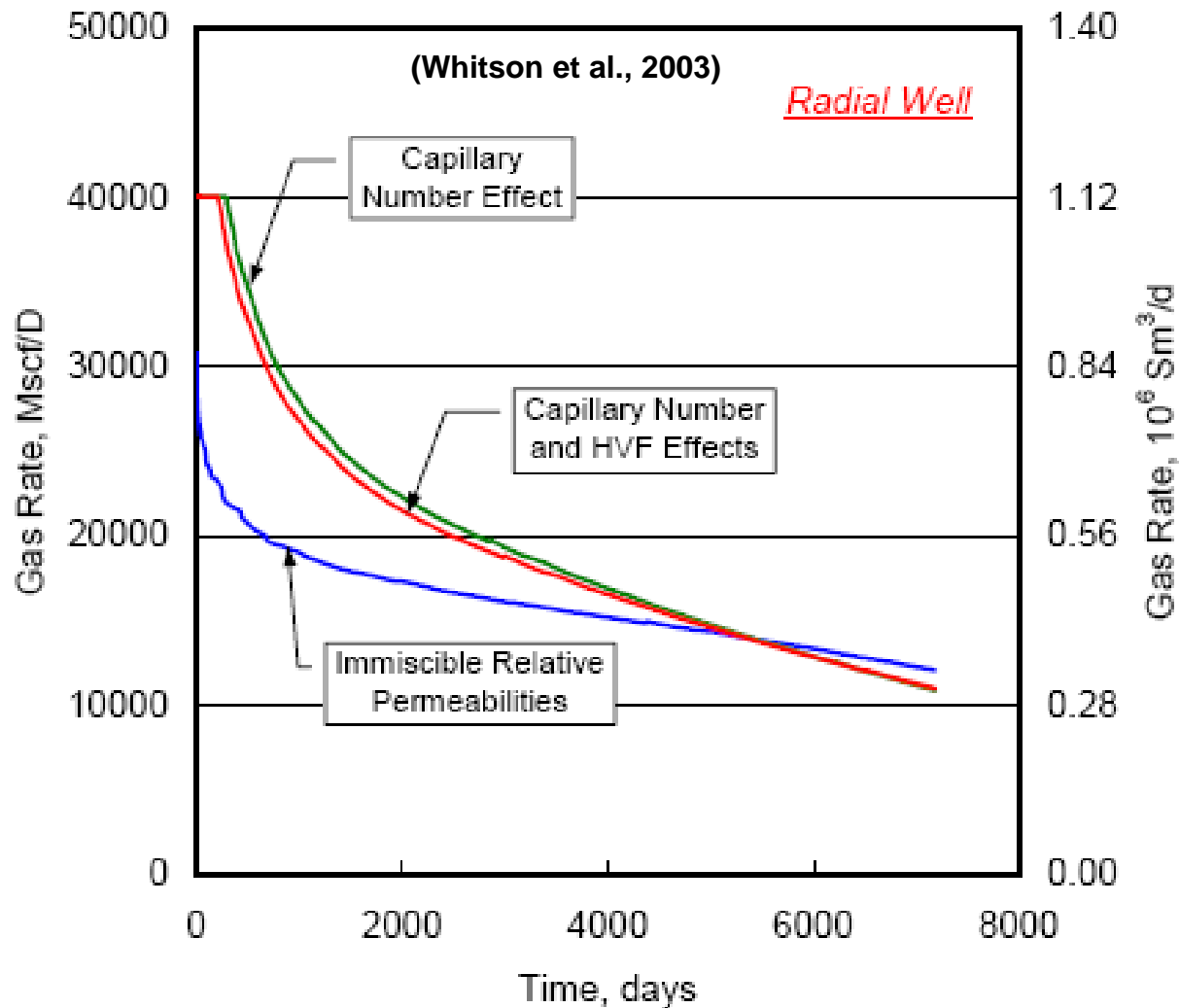
$k_{rg, HVF}$  is defined such that the pressure drop using only two-phase Darcy's law with  $k_{rg, HVF}$  is equal to the pressure drop using two-phase Forchheimer equation.

$$\frac{k_{rgHVF}}{k_{rg}} = \left[ 1 + \frac{k \cdot k_{rg}}{\mu_g} \cdot \beta_{\text{eff}} \cdot \rho_g \cdot V_g \right]^{-1}$$

$$k_{ro} = k_{rgHVF} / (k_{ro} / k_{rg})$$



Example of gas relative permeability variation with pressure for radial flow geometry in a rich gas condensate well using proposed steady-state pseudopressure model; shows effect of  $N_c$  dependence on  $k_{rg}$  and effect of inertial HVF ('turbulence') on capillary number.

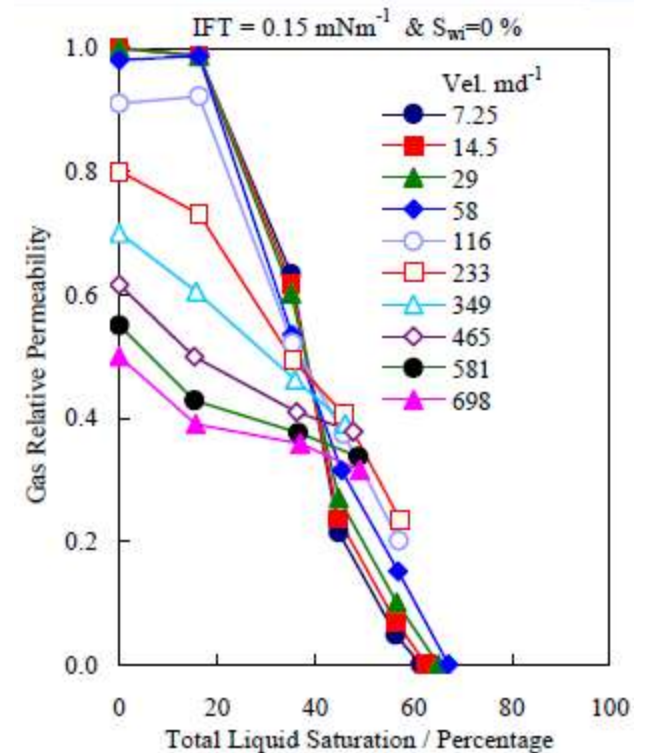
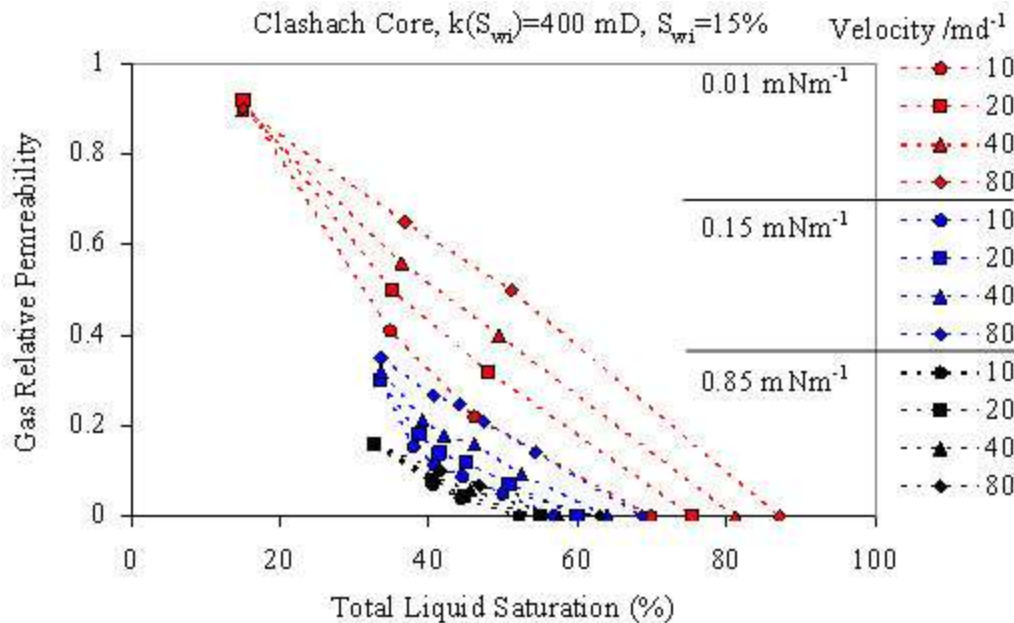


Rate–time behavior for a rich gas condensate radial well showing the effect of including capillary number improvement of  $k_{rg}$ , and inertial high velocity flow ('turbulence').

# Gas Condensate Reservoirs- Fluid Behavior Near-wellbore Phenomena (Danesh, *et al.*, 1994)

➤ Positive Coupling  $\longrightarrow$   $K_r$  increase

➤ Negative Inertia  $\longrightarrow$   $K_r$  decrease



# Theory of Steady-State Compositional Flow

□ the system of equations describing the flow of a two-phase multi-component mixture in porous medium

$$\phi \frac{\partial(\zeta^{(k)} \rho)}{\partial t} + \text{div}(V_g \phi (1-s) \rho_g c_g^{(k)} + V_o \phi s \rho_o c_o^{(k)}) = 0, \quad (k = 1, \dots, N) \quad (2.1)$$

$$U_g \phi (1-s) = -\frac{k k_{rg}(s)}{\mu_g} \text{grad } P_g, \quad U_o \phi s = -\frac{k k_{ro}(s)}{\mu_o} \text{grad } P_o \quad (2.2)$$

$$\zeta^{(k)} = \frac{\rho_g c_g^{(k)} (1-s) + \rho_o c_o^{(k)} s}{\rho_g (1-s) + \rho_o s}, \quad (k = 1, \dots, N);$$

$$\rho = \rho_g (1-s) + \rho_o s \quad (2.3)$$

$$\eta_g^{(k)}(P_g, c_g^{(1)}, \dots, c_g^{(N)}) = \eta_o^{(k)}(P_o, c_o^{(1)}, \dots, c_o^{(N)}), \quad (k = 1, \dots, N); \quad P_g = P_o + P_c(s) \quad (2.4)$$

$$\rho_g = \rho_g(P_g, c_g^{(1)}, \dots, c_g^{(N)}), \quad \rho_o = \rho_o(P_o, c_o^{(1)}, \dots, c_o^{(N)}) \quad (2.5)$$

$$\sum_{k=1}^N c_g^{(k)} = 1, \quad \sum_{k=1}^N c_o^{(k)} = 1 \quad (2.6)$$

## Linear system

$$(\nabla \cdot \Phi) = \frac{\partial \Phi}{\partial x}$$

$$(\nabla^2 \Phi) = \frac{\partial^2 \Phi}{\partial x^2}$$

## Radial system

$$(\nabla \cdot \Phi) = \frac{1}{r} \frac{\partial}{\partial r} (r \Phi_r)$$

$$(\nabla^2 \Phi) = \frac{1}{r} \frac{\partial}{\partial r} \left( r \frac{\partial \Phi}{\partial r} \right)$$

where

$\phi$  : the porosity

$\mathbf{k}$  : permeability

$\mathbf{k}_{rg}(\mathbf{s})$  and  $\mathbf{k}_{ro}(\mathbf{s})$ : the relative gas and condensate (oil) permeabilities

$\mathbf{P}_c(\mathbf{s})$ : capillary pressure

$\zeta^{(k)}$ : total mass concentration of  $k^{\text{th}}$  component in the system

$\mathbf{c}_g^{(k)}$ : the mass concentration of  $k^{\text{th}}$  component in gas;

$\mathbf{c}_o^{(k)}$ : the mass concentration of  $k^{\text{th}}$  component in oil;

$\rho$ : total density;

$\rho_g$  and  $\rho_o$ : gas and the oil densities;

$\mu_g$  and  $\mu_o$  : gas and oil viscosities;

$\mathbf{V}_g$  and  $\mathbf{V}_o$  : the true gas and oil flow velocities;

$\mathbf{P}_g$  and  $\mathbf{P}_o$  : the gas and oil pressures;

$\eta_o^{(k)}$  and  $\eta_g^{(k)}$ : the chemical potentials of  $k^{\text{th}}$  component in oil and gas

$\mathbf{s}$  is not the traditional pore-volume saturation, but it represents the fraction of flowing mixture volume

$$s \equiv v_{T0} = v_o / (v_o + v_g) = q_o / (q_o + q_g)$$