Well Testing Fundamentals

What is a test?

Measurement of rate, time and pressure under controlled conditions.

Why test?

- Reservoir pressure
- Permeability
- Wellbore damage
- Deliverability
- Reservoir management
- Reservoir description
- Fluid samples
- Regulations

+ Well testing theory is based on constant rate Drawdown tests. Drawdown tests are not very practical (due to poor data quality). Buildup tests are more common.

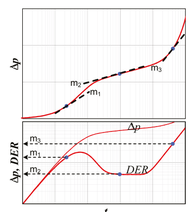
Transient Tests ⟹	Reservoir Characterization
RFT®, WFT®, MDT® …	p_i, k, fluid samples
DST	p_i, k, fluid samples
Drawdown* / Injection	k, s (often un-interpretable)
Buildup* / Falloff	$k, s, \bar{p}_R$
Interference/Pulse	$k, \phi c_t$, lateral/vertical continuity
PITA, PID, Minifrac, CCT	p_i, k
Stabilized Tests ⟹	**Deliverability Forecasting**
IPR	q_{stab}
AOF	q_{stab}

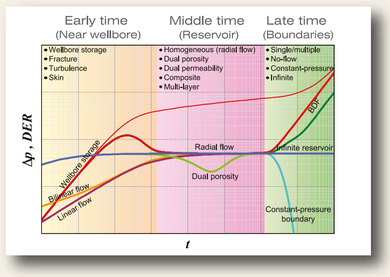
Derivative

- Derivative (DER) is the slope of the semilog plot.

$$DER = \frac{d\Delta p}{d\ln t} = t\frac{d\Delta p}{dt}$$

- DER is usually plotted on log-log coordinates, combined with a plot of Δp.
- DER is used for flow regime diagnostics.

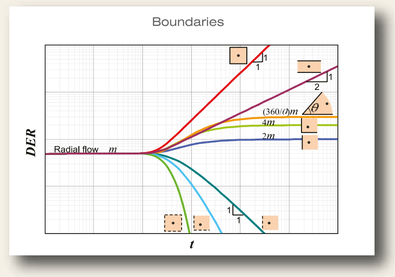




CONSTANT RATE FUNDAMENTALS

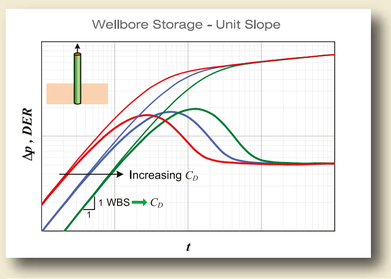
Flow regime		Derivative Slope	Time Function*	Result
Wellbore storage		1	t	C, C_D
Bilinear flow		1/4	$\sqrt[4]{t}$	$k^{1/4}\sqrt{k_f w}$
Linear flow	fracture	1/2	$\sqrt{t}$	$x_f\sqrt{k}$
	horiz. well			$L_e\sqrt{k_y}$
Spherical flow		-1/2	$1/\sqrt{t}$	$\sqrt[3]{k_x k_y k_z}$
Vertical radial flow in horizontal wells		0	$\log(t)$	$L_e\sqrt{k_x k_z}$
Radial flow (∞-acting)		0	$\log(t)$	kh
Linear flow – Channel		1/2	$\sqrt{t}$	$W\sqrt{k}$
Boundary-Dominated Flow		1	t	V_p

** x-axis of specialized plots.*



FLOW REGIMES

STORAGE

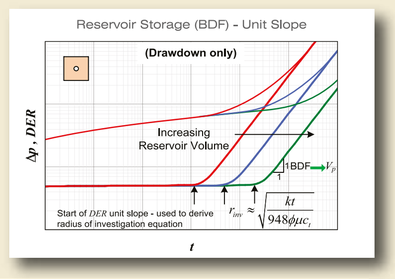


Storage Flow Regime is equivalent to emptying a tank

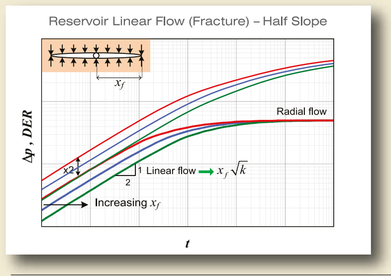
$$c = \frac{-1}{V}\frac{\Delta V}{\Delta p} = \frac{-1}{V}\frac{qt}{\Delta p}$$

Early time: Wellbore Storage (WBS)
- Pressure and derivative have unit slope

Late time: Boundary-Dominated Flow (BDF)
- Also known as:
  - Pseudo-steady state
  - Stabilized
  - Tank-type behavior
- Applies to Drawdown only – **NOT Buildup**
- Derivative unit slope occurs much earlier than pressure unit slope



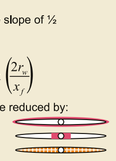
LINEAR FLOW



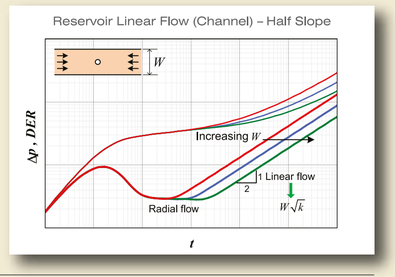
Early Time ⟹ fracture
- Infinite conductivity fracture
- Pressure and derivative have slope of ½ (Separated by a factor of 2)
- Equivalent to negative skin

$$r_{wa} = \frac{x_f}{2} \Rightarrow s = \ln\left(\frac{2r_w}{x_f}\right)$$

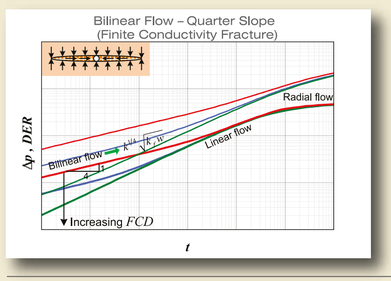
- Fracture effectiveness may be reduced by:
  - Skin on fracture face
  - Choke skin
  - Finite conductivity within the fracture



Late Time ⟹ channel (parallel boundaries)
- Derivative has slope of ½

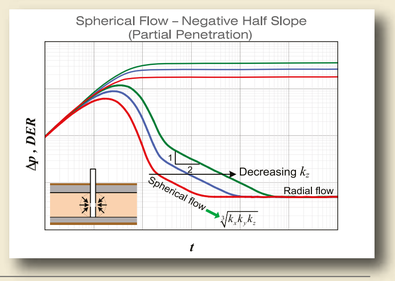


BILINEAR FLOW



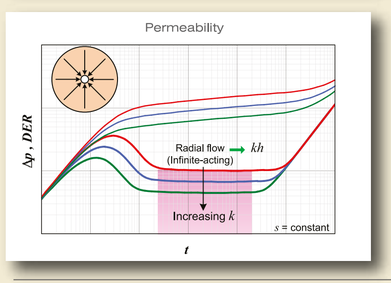
- Finite conductivity fracture
- Dimensionless Fracture Conductivity $FCD = \frac{k_f w}{k x_f}$
- Bilinear flow regime precedes linear flow
- $FCD > 100$ ⟹ infinite conductivity fracture

SPHERICAL FLOW



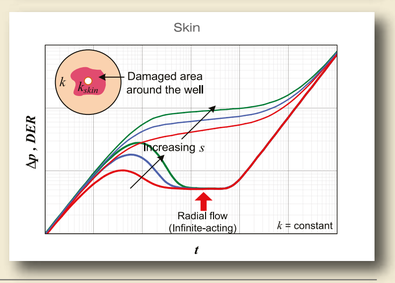
- Partial Penetration or limited perforations
- Slope of derivative is -½
- Component of total skin
- Magnitude of skin depends on vertical permeability and perforation interval
- Radial flow from completed interval may be observed before spherical flow

RADIAL FLOW (INFINITE-ACTING)



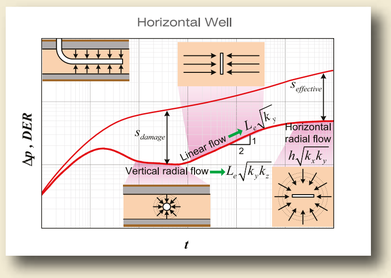
- Derivative has a slope of zero
- Used to obtain permeability

SKIN

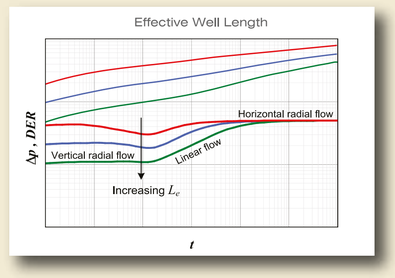


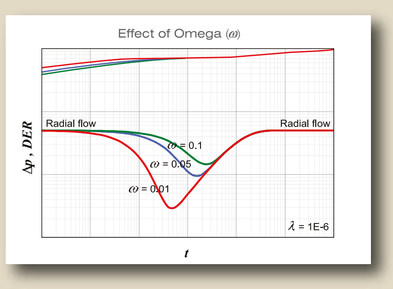
- $\Delta p|_{skin}$ = difference between ideal and measured flowing pressure
- $s = \Delta p|_{skin}$ expressed in dimensionless form
- Skin $s = \left(\frac{k}{k_{skin}} - 1\right)\ln\frac{r_{skin}}{r_w}$
- Apparent wellbore radius $r_{wa} = r_w e^{-s}$; $s = \ln\frac{r_w}{r_{wa}}$
- Total skin, $s' = s_{damage} + s_{turbulence} + s_{partial\ penetration} + s_{geometry} + s_{fracture} + \ldots$

HORIZONTAL WELL FLOW REGIMES



- Vertical radial flow ⟹ vertical permeability, $\sqrt{k_y k_z}$ skin around wellbore, s_{damage}
- Linear flow ⟹ k_y or effective wellbore length, L_e
- Once linear flow is reached, horizontal well is similar to vertical fractured well + $s_{convergence}$
- Horizontal radial flow ⟹ horizontal permeability, $\sqrt{k_x k_y}$, and skin equivalent to vertical well, $s_{effective}$





DUAL POROSITY / PERMEABILITY

- Storativity ratio (ω) gives an indication of the fraction of the hydrocarbons stored in the fissures (porosity 1)

$$\omega = \frac{(\phi c_t h)_1}{(\phi c_t h)_1 + (\phi c_t h)_2}$$, typically 0.01 to 0.1

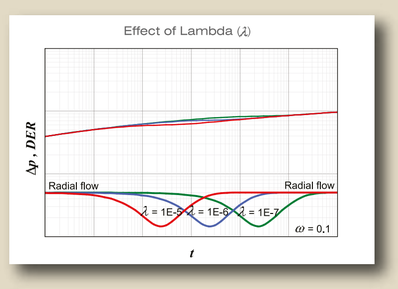
- Interporosity Flow Coefficient (λ) reflects the contrast between matrix and fracture permeability; it also depends on matrix size and geometry

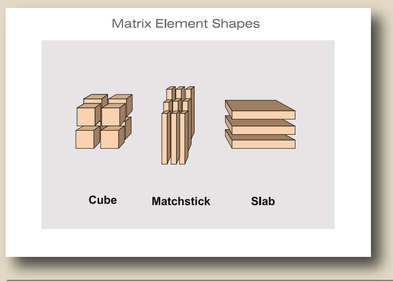
$$\lambda = \alpha\frac{k_2}{k_1}$$, typically 10^{-4} to 10^{-8}

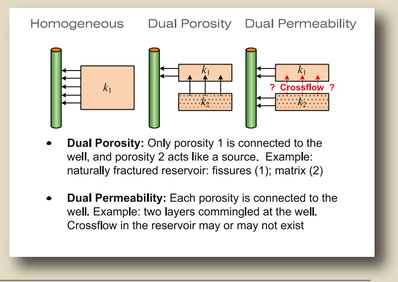
- α is a shape factor that depends on the size and geometry of the matrix
- $\lambda = 0$ ⟹ No crossflow in the reservoir
- Flow Capacity Ratio (κ) is the contribution of the high permeability layer with respect to the total

$$\kappa = \frac{k_1 h_1}{k_1 h_1 + k_2 h_2}$$

- $k_2 \to 0$, $\kappa \approx 1$ ⟹ dual porosity

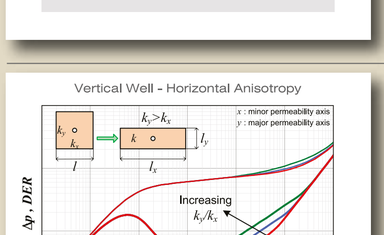






- **Dual Porosity:** Only porosity 1 is connected to the well, and porosity 2 acts like a source. Example: naturally fractured reservoir: fissures (1); matrix (2)
- **Dual Permeability:** Each porosity is connected to the well. Example: two layers commingled at the well. Crossflow in the reservoir may or may not exist

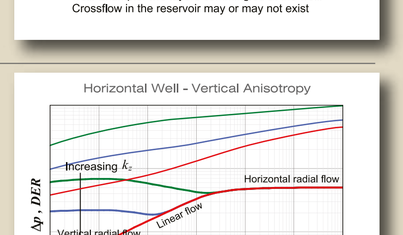
ANISOTROPY



- Anisotropy affects the drainage pattern
- It creates elliptical iso-potentials
- Coordinate transformation converts anisotropic reservoir models to equivalent isotropic ones of different dimensions

$$l_x = l\sqrt{k/k_x} \qquad k = \sqrt{k_x k_y}$$
$$l_y = l\sqrt{k/k_y}$$

- Horizontal anisotropy is important in certain depositional environments; such as naturally fractured reservoirs or coals
- Vertical anisotropy is common and affects skin whenever there is flow in the vertical direction, such as partial penetration



NOMENCLATURE

a, a'	constant in LIT equation
b, b'	constant in LIT equation
B	formation volume factor
c	compressibility
c_d	desorption compressibility
c_f	formation compressibility
c_t	total compressibility
c_{wb}	compressibility of wellbore fluids
C	wellbore storage
D	turbulence factor
DER	semilog derivative for drawdown
h	formation thickness
k	permeability
k_f	permeability in fracture
k_x	permeability in x direction
k_y	permeability in y direction
k_z	permeability in z direction
l	reservoir length
l_x	transformed reservoir length in x direction
l_y	transformed reservoir length in y direction
L_e	effective length of a horizontal well
m	slope of the straight line on specialized plots
p	pressure
p_0	reference pressure
p_b	bubble point pressure
p_p	pseudo-pressure
$p_{\bar{R}}$	average reservoir pressure
p_{wa}	perforation cushion pressure
p_i	Langmuir pressure
p_u	unit rate function
q	flow rate
$q_{o(max)}$	maximum oil flow rate
q_{stab}	stabilized flow rate
r_e	external reservoir radius
r_{inv}	radius of investigation
r_w	wellbore radius
r_{wa}	apparent wellbore radius
s	skin
s'	total skin
S	saturation
t	time
t_a	pseudo-time
t_s	time to stabilization
T	temperature
V	volume
V_L	Langmuir volume
V_p	pore volume
V_{wb}	wellbore volume
w	fracture width
W	channel width
x_f	fracture half length
Z	compressibility factor
Δt	shut-in time

Equations - oil field units

Greek symbols

α	shape factor
Δ	difference
ϕ	porosity
κ	flow capacity ratio
λ	interporosity flow coefficient
μ	viscosity
θ	wedge angle
ρ_B	bulk density
ω	storativity ratio

Subscripts

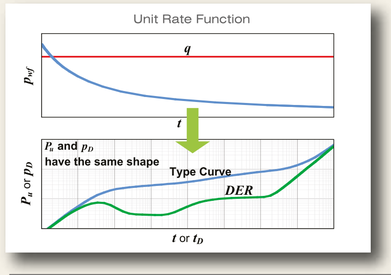
D	dimensionless
g	gas
i	initial
j, n	variable counter
o	oil
$turb$	turbulence
w	water
wf	flowing well
ws	shut-in well

Abbreviations

ACA	after closure analysis
AOF	absolute open flow
BDF	boundary-dominated flow
CCT	closed chamber test
DFIT®	diagnostic fracture injection test
DST	drill stem test
FCD	dimensionless fracture conductivity
FRT®	flow rate tester
IDER	impulse derivative
IPR	inflow performance relationship
MDT®	modular formation dynamic tester
PID	perforation inflow diagnostic
PITA	perforation inflow test analysis
RFT®	repeat formation tester
WBS	wellbore storage
WFT	wireline formation tester

SUPERPOSITION

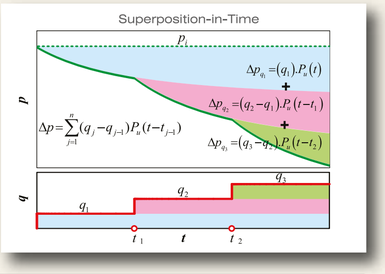
UNIT RATE FUNCTION



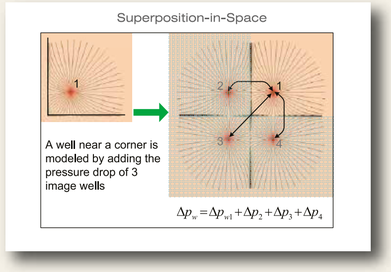
- Unit Rate Function, P_u, is defined as the pressure drop per unit constant flow rate : $P_u = (\Delta p/q)$
- It is the fundamental solution of the Diffusivity Equation used in Well Test Interpretation
- P_u is often expressed in dimensionless form

$$p_D = \frac{\Delta pkh}{141.2qB\mu} \qquad t_D = \frac{2.637E{-}4\ kt}{\phi\mu c_t r_w^2}$$

- It is called a Type Curve when plotted on log-log coordinates, and is usually presented with the semilog derivative $DER = d(p_D)/d(\ln t_D)$
- Every reservoir has its own Unit Rate Function; the shape of its derivative reflects the reservoir model



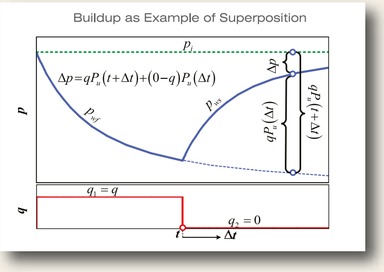
CONVOLUTION



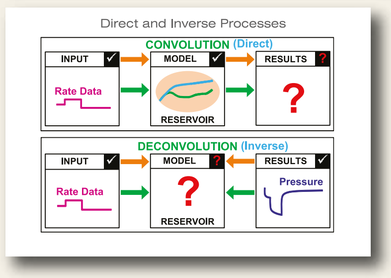
- Superposition is also known as Convolution
- In simple terms, the Principle of Superposition states that the total pressure drop is simply the summation of the individual pressure drops
- It is applied ***in time*** to account for rate changes, and ***in space*** to account for multiple wells and boundaries

SUPERPOSITION-IN-TIME

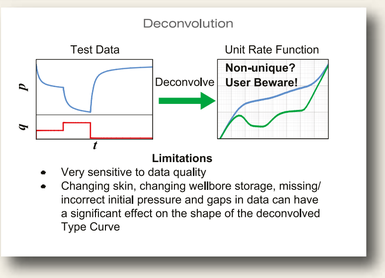
- Superposition-in-time is used to convert the constant rate solution (Pu) to a multi-rate solution
- The rate used for each step is the difference between the current rate and the previous rate
- A rate changing from q_j to q_2 at time t_j, is treated as q_j continuing forever plus $(q_2\text{-}q_j)$ starting at t_j



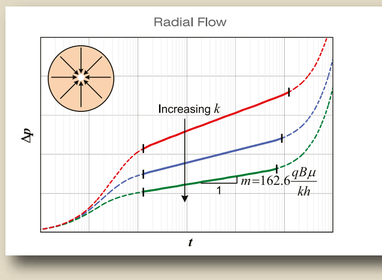
DECONVOLUTION

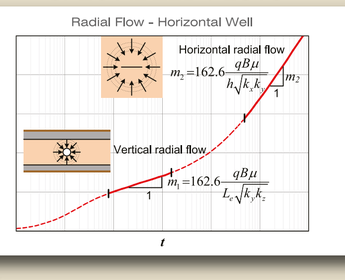


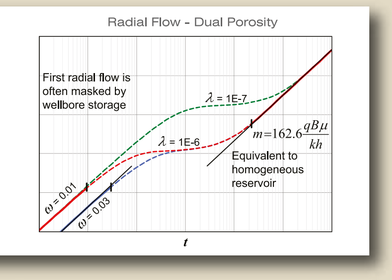
- Deconvolution is the reverse of superposition
- Its purpose is to extract the Unit Rate Function from pressure data in multi-rate tests
- This Unit Rate Function is in fact the reservoir Type Curve; it facilitates identification of the reservoir model
- It does NOT require a pre-conceived reservoir model; rather, it is used to determine what the reservoir model might be
- It is used to convert buildup or multi-rate data into the corresponding constant rate Drawdown Type Curve

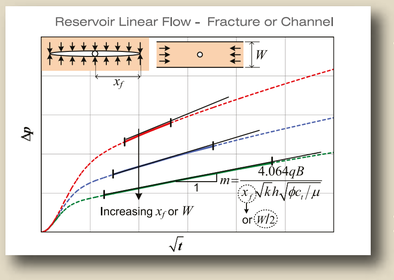


SPECIALIZED PLOTS





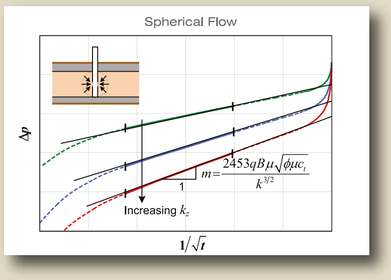




- A specialized plot is a plot of the pressure data on a time axis that is specific to a particular flow regime:

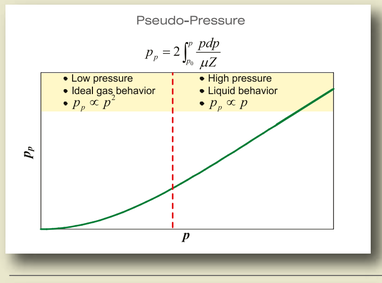
Flow Regime	X-Axis
Radial flow (horizontal)	$\log(t)$
Radial flow (vertical)	$\log(t)$
Linear flow (fracture)	$\sqrt{t}$
Linear flow (channel)	$\sqrt{t}$
Bilinear flow	$\sqrt[4]{t}$
Spherical flow	$1/\sqrt{t}$
Wellbore storage (afterflow)	t
Boundary-dominated flow	t

- It exhibits a straight line during that flow regime
- The slope of the line gives the result of interest



GAS CONSIDERATIONS

PSEUDO-PRESSURE



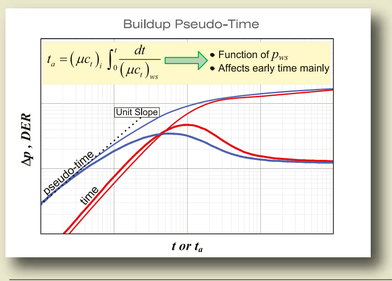
- Welltest equations are based on liquid flow equations:
  - Constant μ
  - Constant c
- Gas properties (μ, c and Z) vary with pressure
- Pseudo-pressure accounts for variations of μ and Z
- Pseudo-pressure is an **exact** transformation
- Replacing p by p_p makes Darcy's Law applicable to gas (when expressed in terms of flow rate at standard conditions)
- p_p does **NOT** account for variation in gas compressibility (c_g) with pressure (see pseudo-time)

Gas: Replace (pressure p ⟹ pseudo-pressure p_p; time t ⟹ pseudo-time t_a)

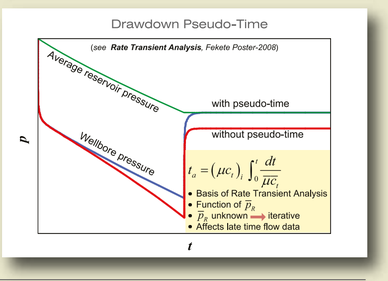
	Liquid	Gas
p_D	$\frac{kh}{141.2qB\mu}(p_i - p_{wf})$	$\frac{kh}{1.417E6qT}(p_{pi} - p_{pwf})$
t_D	$\frac{0.0002637kt}{\phi\mu c_t r_w^2}$	$\frac{0.0002637kt_a}{\phi(\mu c_t)_i r_w^2}$
c_t	constant	Varies with pressure
	$S_g c_g + S_w c_w + S_{wf} c_{wf} + c_f$	$S_g c_g + S_o c_o + S_w c_w + c_f + c_d^{**}$

**CBM desorption compressibility, $c_d = \frac{\rho_B B_g V_L}{\phi}\frac{p_L}{(p_L + p)^2}$

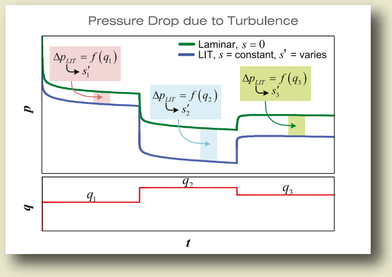
PSEUDO-TIME (t_a)



- Pseudo-time (t_a) corrects for variation of gas viscosity (μ_g) and compressibility (c_g) with pressure
- At low pressure c_g varies significantly ⟹ $c_g \approx \frac{1}{p}$
- Pseudo-time transformation is **not exact**
- Pseudo-time is defined **DIFFERENTLY** for drawdown and buildup
  - In well testing (buildup analysis) pseudo-time is defined in terms of pressure at the **wellbore**
  - For analysis of production data (long drawdowns) pseudo-time is defined in terms of the **average reservoir pressure** NOT the wellbore pressure



TURBULENCE (HIGH VELOCITY NON-DARCY FLOW)

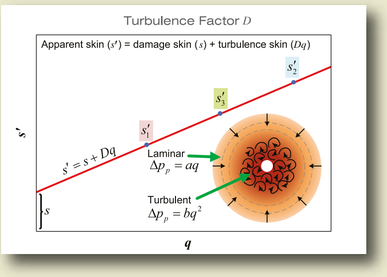


- Gas flow within the reservoir can be laminar or turbulent
- Velocity increases as the wellbore is approached
- Turbulence near the wellbore area causes an additional pressure drop that is treated as skin
- Skin due to turbulence is rate-dependent
- Multiple rates are required to quantify turbulence
- Positive skin usually means damage; however it could represent a stimulated well with turbulence

LAMINAR-INERTIAL-TURBULENT (LIT) FLOW

(Forchheimer or Houpeurt Equation)

$\Delta p_p = aq + bq^2$ or sometimes $\Delta p^2 \approx a'q + b'q^2$

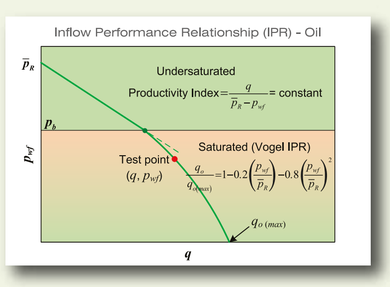


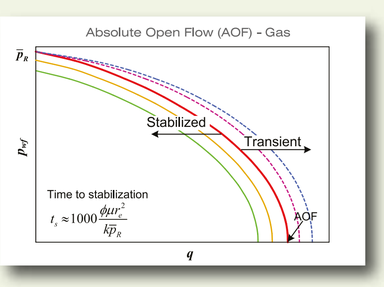
STABILIZED TESTS

IPR FOR OIL …. AOF FOR GAS

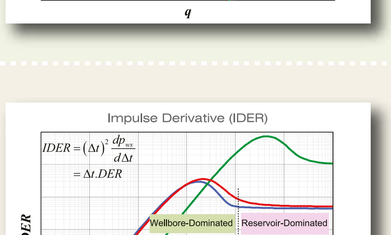
Deliverability Tests : Evaluate deliverability, **NOT** reservoir characteristics

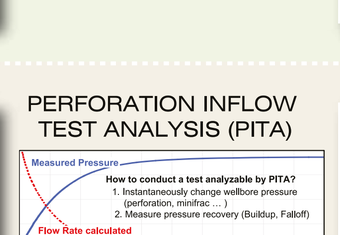
- **IPR :** Inflow Performance Relationship
  - Flow potential of a well at any sandface pressure
  - Single point test
- **AOF :** Absolute Open Flow
  - Maximum rate of a gas well when back pressure at sandface is zero
  - Multiple rates required to evaluate turbulence



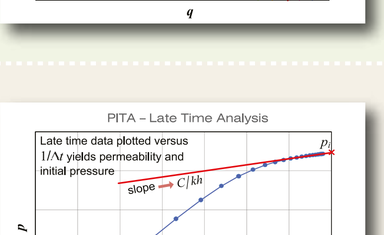


PERFORATION INFLOW TEST ANALYSIS (PITA)





- Pre-frac test
- Useful for determining initial pressure and permeability of low permeability reservoirs
- PITA is similar to other tests:
  Slug, Surge®, Impulse®, Perforation Inflow Diagnostic (PID), Closed Chamber Test (CCT), Flow Rate Tester (FRT®), DFIT®, Minifrac, After-Closure-Analysis (ACA), ...



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Well Testing Fundamentals

All analyses described can be performed using IHS's Well Testing software IHS WellTest.