Well Testing Applications

WELL TEST INTERPRETATION PROCESS

Step 1: Data Verification

- Compare recorders
  - Subtraction highlights inconsistencies
- Prepare wellbore schematic
  - Note RRD compared to MPP (Convert pressure to datum)
- Review completion
  - Hydraulic fracture size, fluids left to recover
  - Do not ignore production during clean-up
- Review previous production history
  - Include all relevant production, not only when pressure measurement started
- Review field notes for test operations
  - Compare wellhead and sandface pressures
  - Look for operational problems such as liquid loading, hydrating, multiphase, changing liquid-to-gas ratios
- Check for increasing PPD
  - Any data affected by increasing PPD must be excluded from reservoir interpretation

Step 2: Diagnostic Analysis

- Select flow period with longest and best quality data
- Conduct Diagnostic and Specialized Analyses

Early Time	Middle Time	Late Time
• Check wellbore storage for reasonableness • Obtain fracture characteristics • Create $\sqrt{t}$ or $1/\sqrt{t}$ specialized plot	• Determine permeability and skin • Create semilog t specialized plot (Horner)	• Heterogeneities and boundaries • Complex reservoir geometry • Boundary-dominated flow

Step 3: Modeling

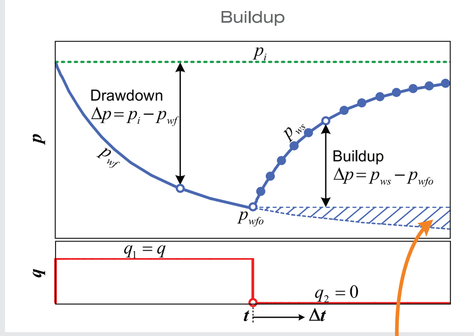
- Select model based on Diagnostic Analysis and geological description
- History-match selected flow periods
- Confirm model by extending history match to other flow/shut-in data
- Exclude inconsistent data when matching
- Use model for forecasting future production

Readily available models:

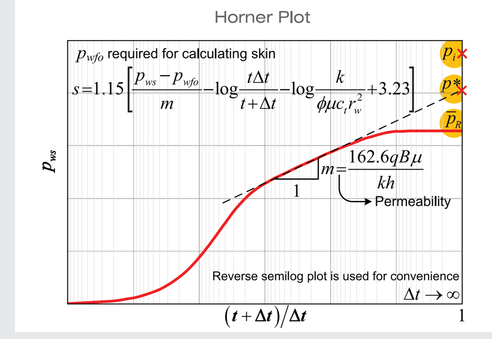
- Vertical / Horizontal Well
- Full / Partial Penetration
- Finite / Infinite Conductivity Fracture
- Dual Porosity / Permeability
- Isotropic / Anisotropic
- Observation Well
- Circular / Rectangular
- Composite / Multilayer
- Wedge / Leaky Fault
- PITA / CCT / RFT®

BUILDUP FUNDAMENTALS

Buildup



Horner Plot



BUILDUP ANALYSIS

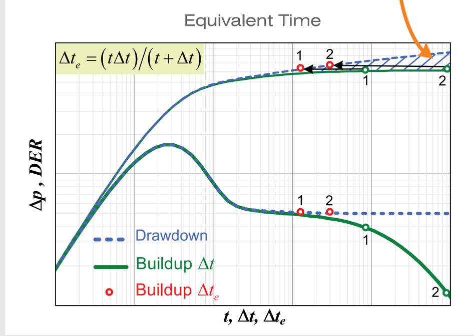
- Drawdown tests are often not analyzable because of poor data quality
- Buildup tests have fewer data quality issues because the well is shut-in
- Buildup analysis is treated as the superposition of flow (q) and injection (0-q)
- Horner time is the simplified superposition time for radial flow

For gas, replace time with pseudo-time (t_a), and pressure with pseudo-pressure (p_p)
(see ***Well Testing Fundamentals***, *Fekete Poster - 2009*)

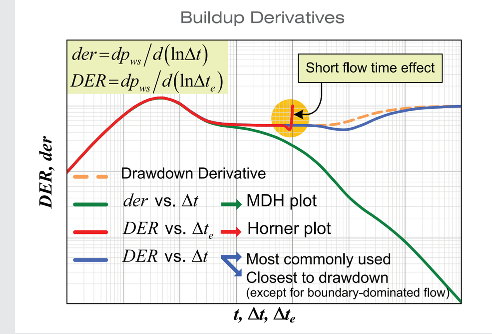
HORNER / MDH PLOT

- **Horner plot**: graph of p_{ws} vs. $\log\left((t+\Delta t)/\Delta t\right)$
  - Extrapolation to infinite shut-in time yields p^*
  - Infinite reservoir: $p^* = p_i$
  - Finite reservoir: $p^* \neq p_i \neq \bar{p}_R$
  - If $p^* > p_i$, the Horner semi-log line is wrong, p_i is wrong, or there is a constant pressure boundary
- **MDH plot**: graph of p_{ws} vs. $\log(\Delta t)$
  - Useful when producing time (t) is long
  - Analysis only valid when $\Delta t < 10\%$ of t

Equivalent Time



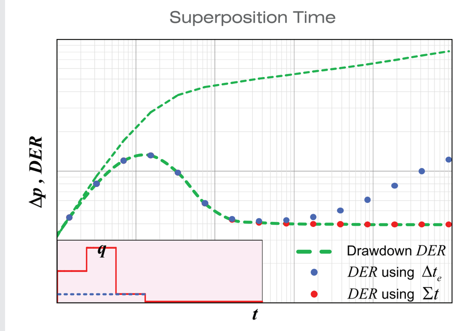
Buildup Derivatives



EQUIVALENT TIME

- Equivalent time (Δt_e) transforms *buildup time* into the equivalent *drawdown time*, so it can be matched to the standard drawdown type curves
- Maximum value of (Δt_e) is the producing time (t)
- Superposition Equivalent Time is used when the flow rate has not been constant

Superposition Time



VARYING RATES

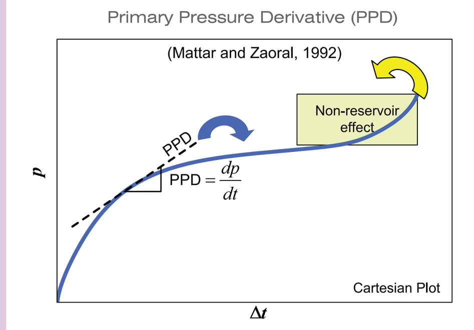
- If production rates change significantly just before shut-in, superposition time (Σt) must be used instead of Horner time
- For smoothly changing rates, a simplification called "effective producing time" (t_p or t_c) can be used
- t_p honours two important criteria:
  - It preserves material balance
  - It uses the flow rate immediately prior to shut-in (NOT the average rate)
- Rate fluctuations that occurred a long time ago (more than two times the buildup duration) can be simplified similarly

Buildup Time Functions

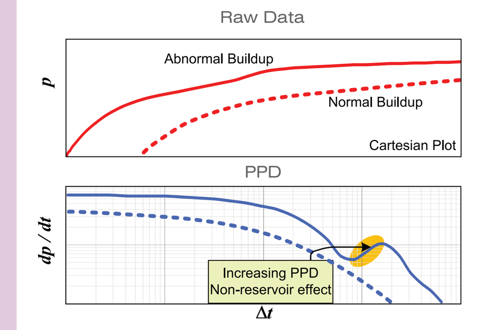
Producing time	t (constant)
Shut-in time (MDH)	Δt (variable)
Horner time	$(t+\Delta t)/\Delta t$
Equivalent time (Δt_e)	$t\Delta t/(t+\Delta t)$
Effective producing time	t_p (or t_c) = Q/q_{last}
Superposition time (Σt)	$\sum_{1}^{n+1}\left\{\frac{\Delta q_j}{q_n}\log\left(t+\Delta t-t_{j-1}\right)\right\}$
Super-equivalent-time	$\sum_{1}^{n}\left\{\frac{\Delta q_j}{q_n}\log\left(\frac{t+\Delta t-t_{j-1}}{t-t_{j-1}}\right)\right\}-\log\Delta t$
Pseudo-time (gas only)	$t_a = (\mu c)_i \int_0^t \left(dt/(\mu c)_{ws}\right)$

DATA VALIDATION / ANOMALIES / ERRORS

Primary Pressure Derivative (PPD)



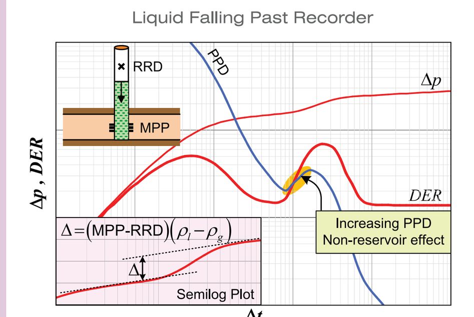
Raw Data



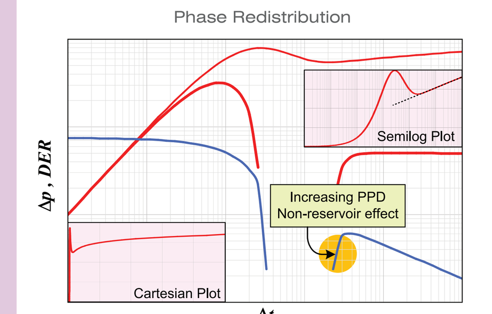
PRIMARY PRESSURE DERIVATIVE (PPD)

- No matter how complex a reservoir is, a buildup (*in Cartesian coordinates*) will ALWAYS be continuously concave downward for a single phase fluid (*except multilayer reservoirs with unequal p_i*)
- Reservoir effects cannot cause an increase in PPD. Therefore an increase in PPD indicates a non-reservoir effect
- Wellbore and reservoir effects can be distinguished through the PPD
- Data preceding or following a segment of increasing PPD may be valid
- It is not practical to use PPD as a diagnostic for drawdown analysis because of rate changes and noisy measurements

Liquid Falling Past Recorder



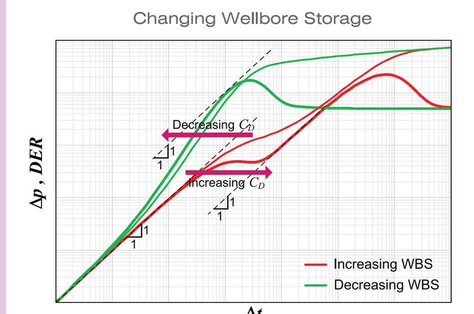
Phase Redistribution



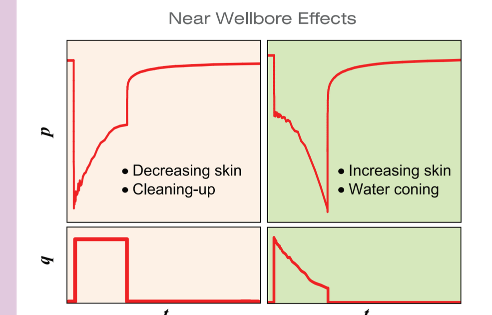
WELLBORE DYNAMICS

- **Liquid falling past pressure recorders:**
  - When liquid interface goes past the recorders, it creates a unique signature
  - Often visible as parallel lines on semilog plot
  - Can occur any time
  - When it occurs at late time, it is often mis-interpreted as a boundary
  - Identified by increasing PPD
- **Phase redistribution:**
  - Causes increase then decrease in wellbore pressure
  - NOT related to location of recorders
  - Characteristic hump always occurs at early time
  - PPD goes negative before increasing
- **Changing wellbore storage:**
  - Change from liquid to gas-dominated wellbore
  - Changing gas compressibility as function of pressure (pseudo-time)
  - Causes deviation from early time unit slope
  - Theoretical model can be used to model phase redistribution

Changing Wellbore Storage



Near Wellbore Effects



NEAR WELLBORE EFFECTS

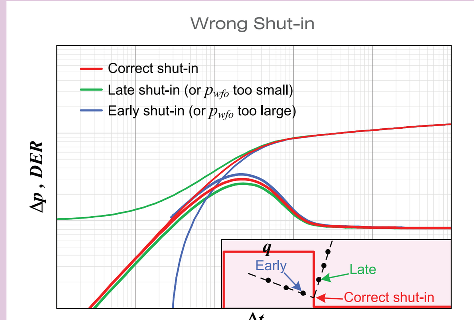
- Multi-phase flow
- Changing skin
  - Near wellbore clean-up → decreasing skin
  - Water coning
  - Hydrate forming near sandface
  - Retrograde condensation
  - Perforation plugging

  } Increasing skin

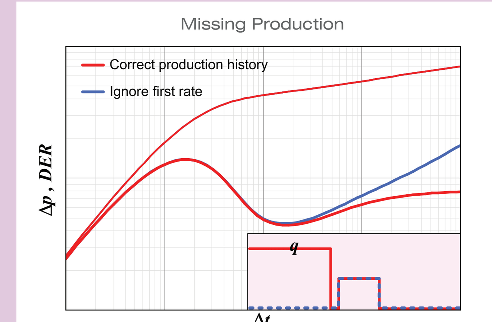
COMMON ERRORS

- **Wrong shut-in:**
  - Wrong Δt: pressure and rate not synchronized
  - Wrong p_{wfo}: noisy pressures at time of shut-in
  - Little effect on derivative
- **Missing production:**
  - Ignoring hydraulic fracture injection/clean-up flow
  - Ignoring production history preceding deployment of pressure gauge
- **Wrong final rate:**
  - The production is often a measured volume, not a rate. When the well is shut-in part way through the day, the reported average daily rate changes, whereas the actual rate does not

Wrong Shut-in

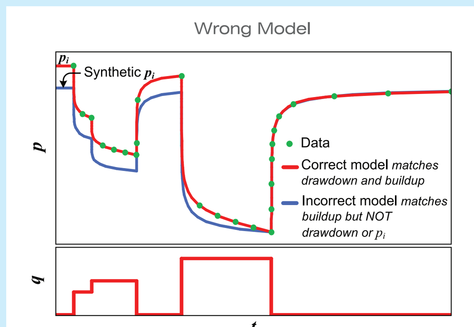


Missing Production



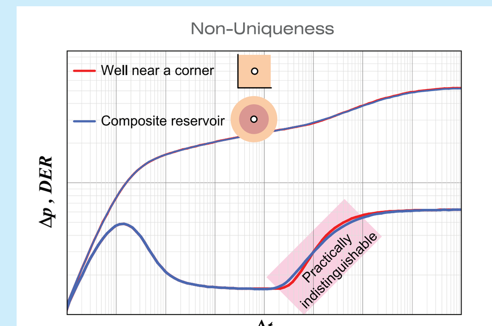
MODELING

Wrong Model



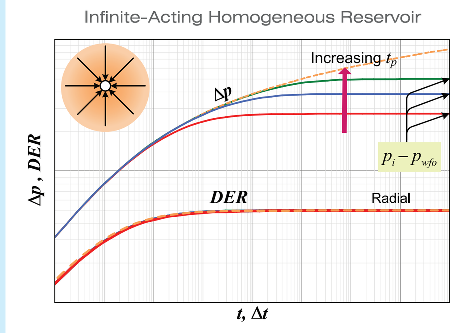
- Modeling (history-matching) should be used to verify results of analyses
- A very good match of the buildup may not match the drawdown data because:
  - The model is wrong (*models are mathematical simplifications of complex geological settings*)
  - The rates may not be accurate (*for buildups, rates can be approximated, but for drawdowns they need to be accurate*)
  - Skin is changing during flow
- It is possible for the ***synthetic initial pressure*** to be significantly in error
- Non-linear regression (automatic history matching) can be used as an aid to modeling, but its results **must** be ratified by the analyst
- It is important to match known endpoints

Non-Uniqueness



BUILDUP (BU) TYPE CURVES

Infinite-Acting Homogeneous Reservoir



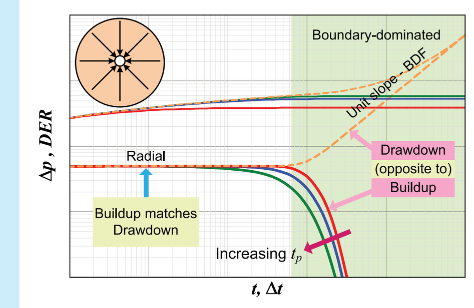
BUILDUP DERIVATIVE, DER

- Calculate DER using superposition equivalent time (Δt_e)
- $DER = dp_{ws}/d(\ln\Delta t_e)$
- Plot DER vs Δt (not Δt_e) on a log-log plot

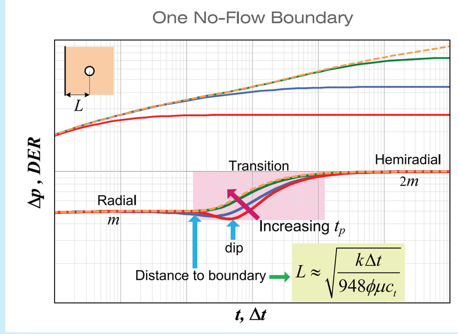
LEGEND

DER	Drawdown		Δp
DER	BU (*short* t_p)		Δp
DER	BU (*medium* t_p)		Δp
DER	BU (*long* t_p)		Δp

Bounded Reservoir



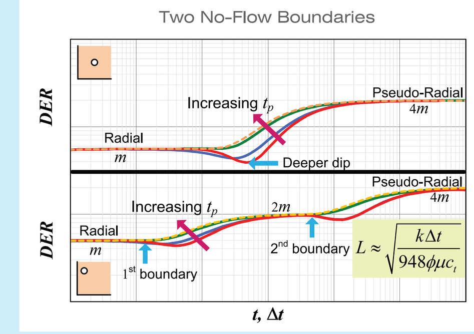
One No-Flow Boundary



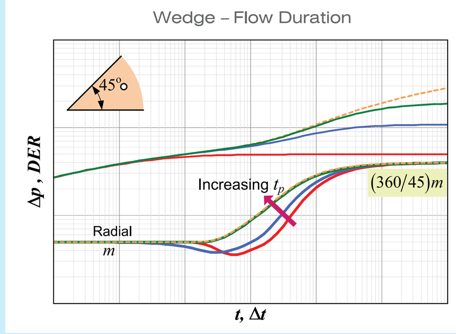
SHAPE OF BUILDUP DERIVATIVE, DER

- **Infinite-Acting Homogeneous Reservoir:**
  - All buildup DER curves match drawdown curves **EXACTLY**
- **Bounded Systems:**
  - During infinite-acting period, buildup DER matches drawdown derivative **EXACTLY**
  - During boundary-dominated period, buildup DER is completely **OPPOSITE** to drawdown
- **One and Two No-Flow Boundaries:**
  - DER matches drawdown during infinite-acting periods
  - Transition lasts 2 log cycles
  - For short flow duration, DER deviates during transition
  - Time of deviation depends on distance to boundary (*radius of investigation equation applies*)
  - DER dips below radial flow line. For two equidistant boundaries, dip is deeper
  - As t_p increases, dip disappears
- **Wedge:**
  - DER is similar to no-flow boundary
  - DER transitions from infinite-acting radial flow, m, to pseudo-radial flow $(360/\theta)m$
- **Parallel Boundaries:**
  - Late-time linear flow half-slope is displaced from drawdown by factor of 2. Calculated channel width will be two times actual width

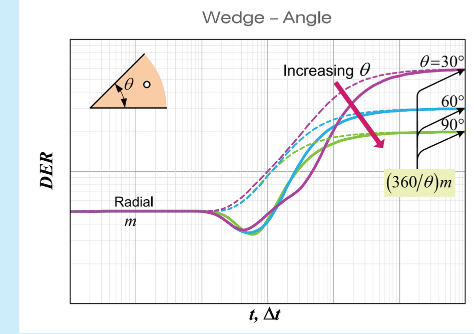
Two No-Flow Boundaries



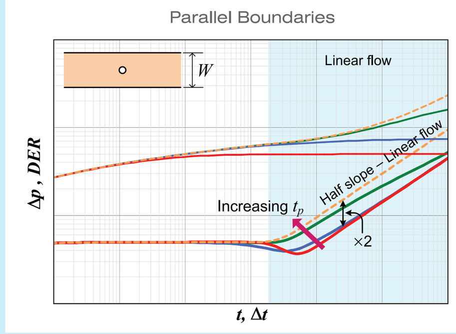
Wedge – Flow Duration



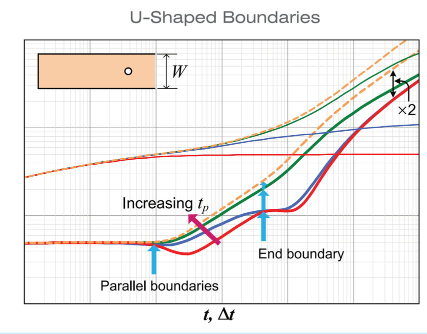
Wedge – Angle



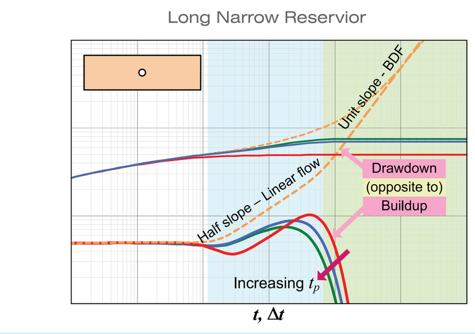
Parallel Boundaries



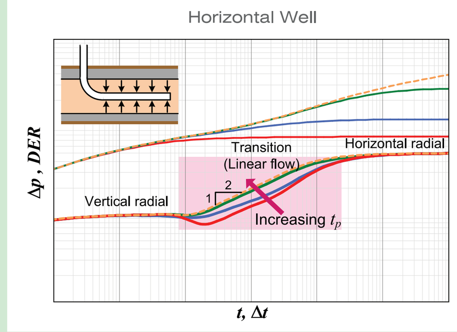
U-Shaped Boundaries



Long Narrow Reservoir

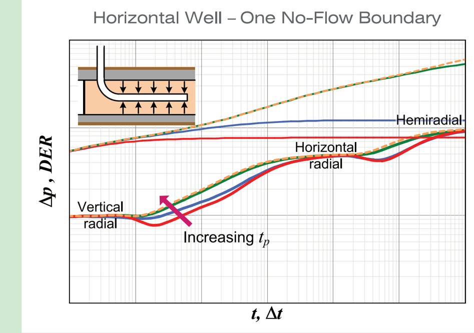


Horizontal Well

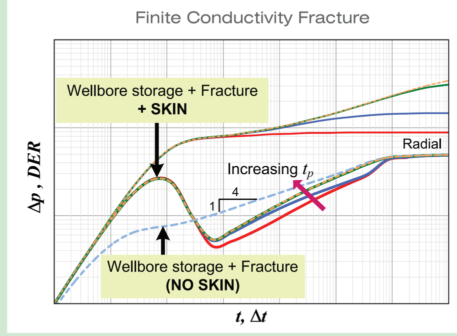


- **Horizontal Well:**
  - If all flow regimes are evident, k_x, k_y and k_z can be determined individually
  - Effective length L_e can be determined if k_y is assumed (often equal to k_x)
  - After end of vertical radial flow, horizontal well behavior is very similar to infinite-conductivity fracture
    - → Replace L_e by $2x_f$, and add a geometric skin due to flow convergence into horizontal well
  - Horizontal well with multiple transverse infinite-conductivity fractures
    - → Initially behaves like a single large fracture, equal in area to the sum of the individual fractures
    - → After interference between the fractures, behaves like a large stimulated area
  - Finite conductivity vertical fracture intersected by horizontal well does NOT result in bilinear flow
- **Hydraulic Fracture (Vertical Well):**
  - Bilinear flow → Finite conductivity fracture
  - Linear flow → Infinite conductivity fracture
  - Wellbore storage hump is evident when fracture has a skin (choke skin or fracture-face skin). Easily misinterpreted as radial flow with complex reservoir geometry
  - Sometimes difficult to differentiate between infinite and finite conductivity when skin is present
- **Composite Reservoir:**
  - DER similar to no-flow boundary
  - DER transitions from one radial flow, m, to another radial flow, $(k_1/k_2)m$
  - Duration of transition depends on k_2 to k_1 contrast
  - Dip in DER during transition increases with k_1/k_2
  - As t_p increases, dip disappears
- **Multilayer Cylindrical Reservoir**
  - Shape of derivative depends on: p_i, k, h, ϕ, s and r_e of each layer

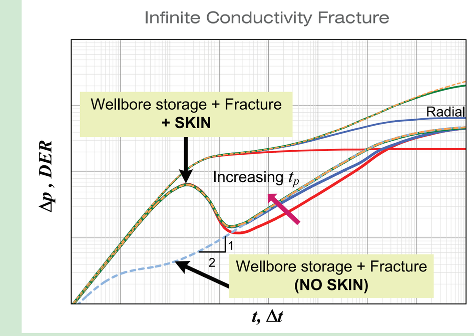
Horizontal Well – One No-Flow Boundary



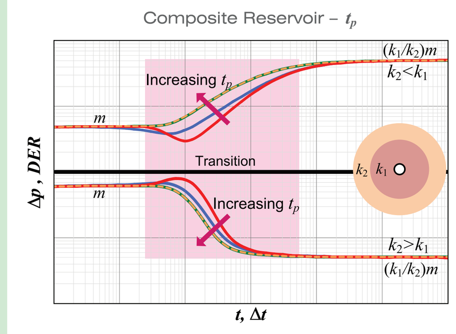
Finite Conductivity Fracture



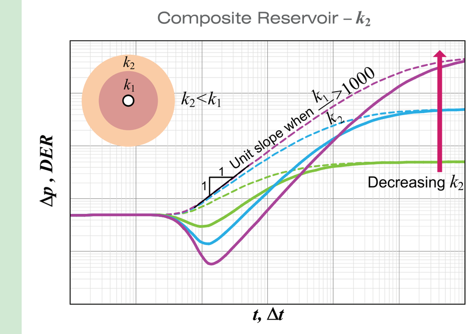
Infinite Conductivity Fracture



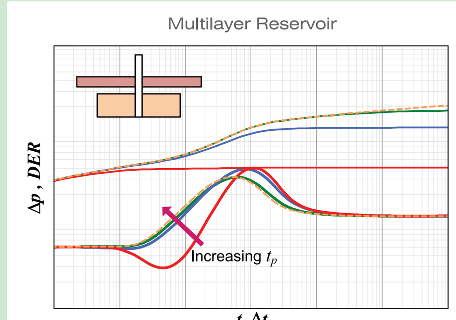
Composite Reservoir – t_p



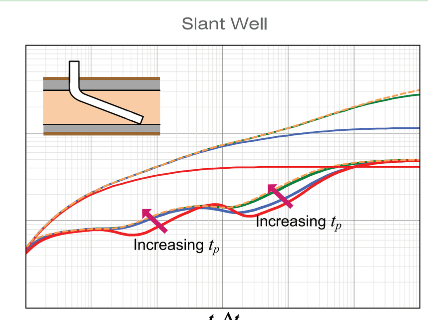
Composite Reservoir – k_2



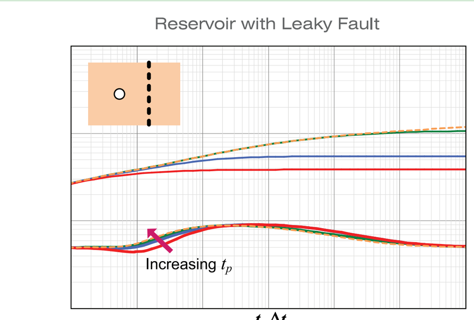
Multilayer Reservoir



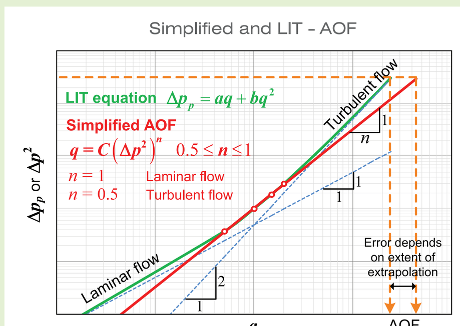
Slant Well



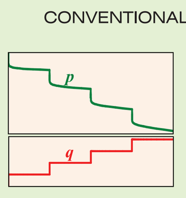
Reservoir with Leaky Fault



Simplified and LIT - AOF

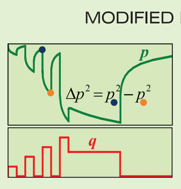


CONVENTIONAL BACK PRESSURE TEST



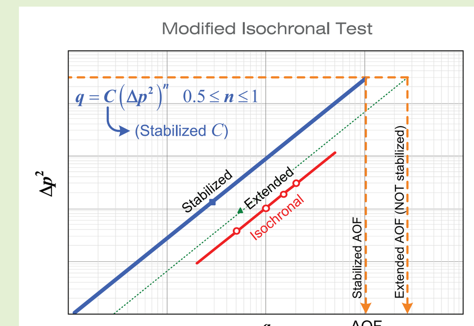
- Flow-after-flow (4 different rates)
- Each rate is sustained until stabilization (BDF)
- Impractical for low permeability reservoirs due to excessive time to reach stabilization

MODIFIED ISOCHRONAL TEST



- At least one rate must be stabilized. If impractical (low permeability), conduct **extended** flow and buildup, and calculate **stabilized** point for correct AOF line
- Equal flow and shut-in periods

Modified Isochronal Test



Reference: **Well Testing Fundamentals**, Fekete Poster - 2009

Nomenclature

a	coefficient in LIT equation
b	coefficient in LIT equation
B	formation volume factor
c_t	total compressibility
C	coefficient in simplified AOF equation
C_D	dimensionless wellbore storage
der	semilog derivative based on shut-in time for buildup
DER	semilog derivative for drawdown; also, semilog derivative based on equivalent time for buildup
h	formation thickness
k	permeability
L	distance to boundary
m	slope of semilog straight line
n	exponent in simplified AOF equation
p	pressure
p^*	extrapolation of semilog straight line to infinite shut-in time
p_i	initial pressure
p_p	pseudo-pressure
$\bar{p}_R$	average reservoir pressure
p_{wfo}	last flowing well pressure before shut-in
q	flow rate
q_{last}	final flow rate before shut-in
Q	cumulative production
r_w	wellbore radius
r_e	external reservoir radius
s	skin
t	time
t_a	pseudo-time
t_c	producing time or effective producing time; same as t_p
t_p	producing time or effective producing time; same as t_c
W	channel width
Δt	shut-in time
Δt_e	equivalent time of shut-in
Σt	superposition time

Greek symbols

Δ	difference
ϕ	porosity
μ	viscosity
θ	wedge angle
ρ_g	gas density
ρ_l	liquid density

Subscripts

i	initial
j, n	variable counter
wf	flowing well
ws	shut-in well

Equations - oil field units

Abbreviations

AOF	absolute open flow
BDF	boundary-dominated flow
BU	buildup
CCT	closed chamber test
LIT	laminar inertial turbulent
MDH	Miller, Dyes and Hutchinson
MPP	mid point of perforations
PITA	perforation inflow test analysis
PPD	primary pressure derivative
RFT®	repeat formation tester
RRD	recorder run depth
WBS	wellbore storage

IHS Markit™

Well Testing Applications

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

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