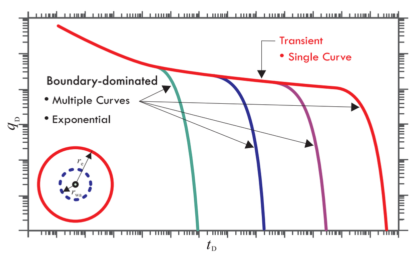
Rate Transient Analysis

Fetkovich Analysis

1. Analytical: Constant Flowing Pressure



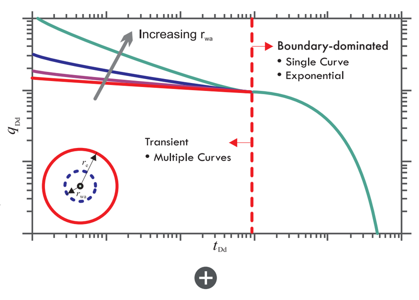
- q_D and t_D definitions are similar to PTA.
- Convenient for transient flow.
- Results in single transient stem but multiple boundary-dominated stems.

$$q_D = \frac{141.2qB\mu}{kh(p_i - p_{wf})}, \quad t_D = \frac{0.00633kt}{\phi\mu c_t r_{wa}^2}$$

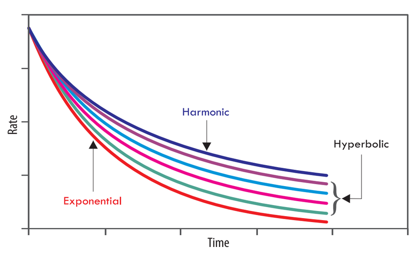
- q_{Dd} and t_{Dd} definitions are standard for production data analysis.
- Convenient for boundary-dominated flow.
- Results in single boundary-dominated stem but multiple transient stems.

$$q_{Dd} = q_D(\ln r_{eD} - 0.5), \quad t_{Dd} = \frac{2t_D}{(\ln r_{eD} - 0.5)(r_{eD}^2 - 1)}$$

2. Analytical: Constant Flowing Pressure

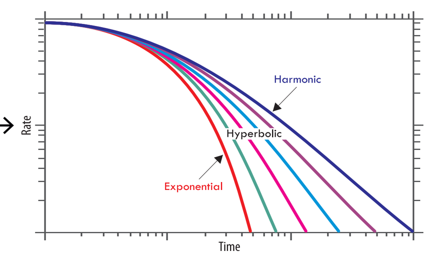


3. Empirical: Arps Depletion Stems

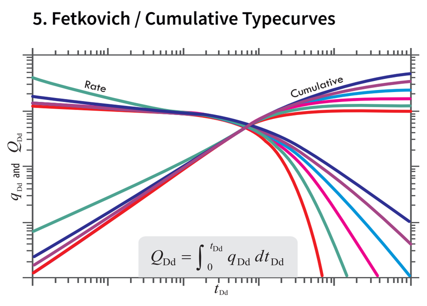


Depletion stems are Arps' declines on a log-log scale

4. Empirical: Arps-Fetkovich Depletion Stems



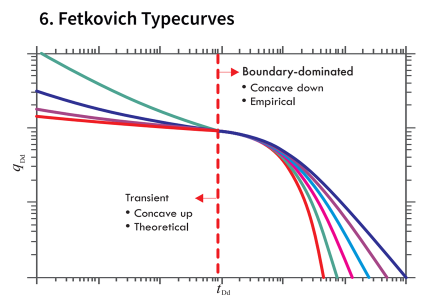
5. Fetkovich / Cumulative Typecurves



Summary:

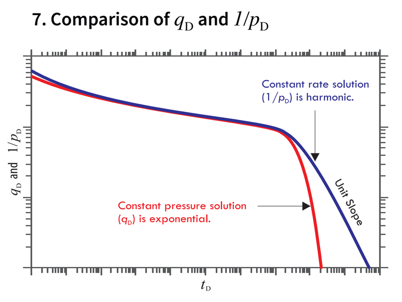
- Combines transient with boundary-dominated flow.
- Transient: Analytical, constant pressure solution.
- Boundary-dominated: Empirical, identical to traditional (Arps).
- Constant operating conditions.
- Used to estimate EUR, skin and permeability.
- EUR depends on operating conditions.
- Does *not* use pressure data.
- Cumulative curves are smoother than rate curves.
- Combined cumulative and rate typecurves give a more unique match (see Figure 5).

6. Fetkovich Typecurves



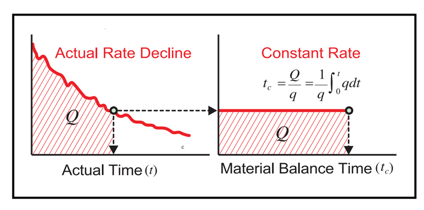
Modern Decline Analysis Concepts

7. Comparison of q_D and $1/p_D$

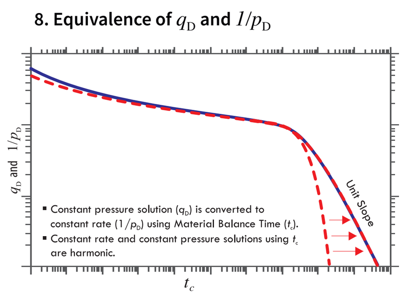


Material Balance Time

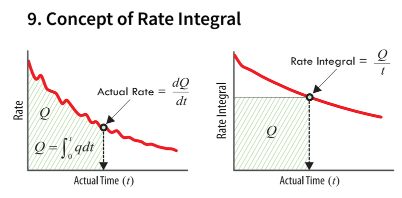
- Material Balance Time (t_c) effectively converts the constant pressure solution to the corresponding constant rate solution.
- The exponential curve plotted using Material Balance Time becomes harmonic.
- Material Balance Time is rigorous during boundary-dominated flow.



8. Equivalence of q_D and $1/p_D$



9. Concept of Rate Integral



- Rate Integral is cumulative average rate.
- Rate integral is an effective way to remove noise.

Typecurve Interpretation Aids

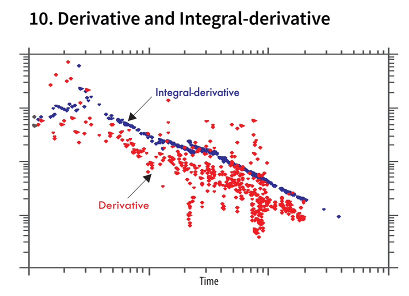
Rate (Normalized)
- Combines rate with flowing pressure. $\frac{q}{\Delta p}$

Integral (Normalized Rate)
- Smoothes noisy data but attenuates the reservoir signal. $\frac{1}{t_c}\int_0^{t_c}\frac{q}{\Delta p}dt$

Derivative (Normalized Rate)
- Amplifies reservoir signal but amplifies noise as well. $\frac{d(\frac{q}{\Delta p})}{d(\ln t_c)}$

Integral-derivative (Normalized Rate)
- Smoothes the scatter of the derivative. $\frac{d}{d(\ln t_c)}\left(\frac{1}{t_c}\int_0^{t_c}\frac{q}{\Delta p}dt\right)$

10. Derivative and Integral-derivative



Gas Flow Considerations

11. Darcy's Law

- Liquid (Constant Viscosity): $\Delta p \propto q$
- Gas: Viscosity and Z-factor are not constant. Define Pseudo-pressure (p_p):

$$p_p = 2\int_{p_0}^{p}\frac{p\,dp}{\mu_g Z}$$

Pseudo-pressure (p_p) corrects for changing viscosity (μ_g) and Z-factor with pressure.

Darcy's Law for Gas: $\Delta p_p \propto q$

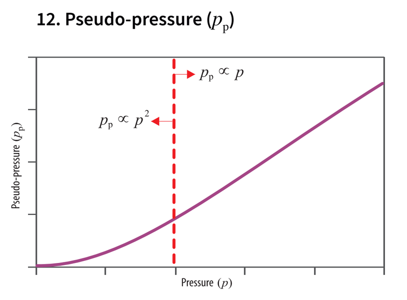
Pseudo-pressure

Gas properties vary with pressure:
- Z-factor (Pseudo-pressure, see Figures 11 & 12).
- Viscosity (Pseudo-pressure & Pseudo-time, see Figures 11, 12 & 14).
- Compressibility (Pseudo-time, see Figures 13 & 14).

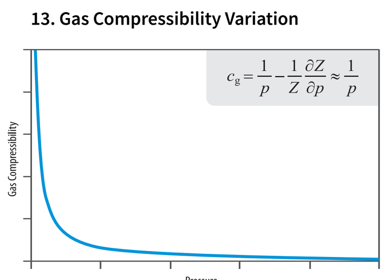
- Pseudo-pressure corrects for changing viscosity and Z-Factor with pressure.
- In all equations for liquid, replace pressure (p) with pseudo-pressure (p_p).

Note: For gas, $q_D = \frac{1}{p_D} = \frac{1.417\times10^6 qT}{kh(p_{pi} - p_{pwf})}$

12. Pseudo-pressure (p_p)



13. Gas Compressibility Variation



Pseudo-time

- Compressibility represents energy in a reservoir.
- Gas compressibility is a strong function of pressure (especially at *low pressures*).
- Ignoring compressibility variation can result in significant error in original gas-in-place (G) calculations.
- Pseudo-time (t_a) corrects for changing viscosity and compressibility with pressure.
- The calculation of pseudo-time is *iterative* because it depends on $\bar\mu_g$ and $\bar c_t$ at average reservoir pressure, and average reservoir pressure depends on G (usually unknown).

Note: Pseudo-time in build-up testing is evaluated at well flowing pressure *not* at average reservoir pressure.

14. Pseudo-time (t_a)

- In all equations for liquid, replace time (t) with pseudo-time (t_a)

$$t_a = (\mu_g c_t)_i \int_0^t \frac{dt}{\bar\mu_g \bar c_t}$$

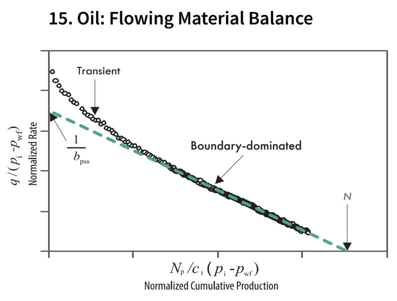
- Convert material balance time (t_c) to material balance pseudo-time (t_{ca}).

$$t_{ca} = \frac{1}{q}\int_0^{t_a} q\,dt_a = \frac{(\mu_g c_t)_i}{q}\int_0^t \frac{q\,dt}{\bar\mu_g \bar c_t}$$

Note: $\bar\mu_g$ and $\bar c_t$ are evaluated at average reservoir pressure (unlike PTA).

Flowing Material Balance

15. Oil: Flowing Material Balance



Oil

$$p_i - p_{wf} = \frac{N_p}{c_t N} + qb_{pss}$$

$$\frac{q}{p_i - p_{wf}} = -\frac{N_p}{c_t N b_{pss}(p_i - p_{wf})} + \frac{1}{b_{pss}}$$

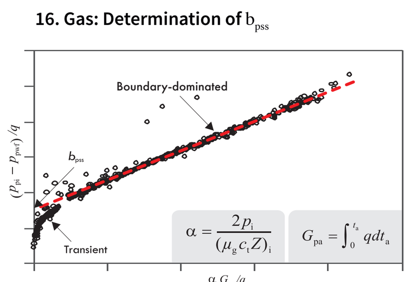
Gas

$$p_{pi} - p_{pwf} = \frac{\alpha G_a}{G_i} + qb_{pss}$$

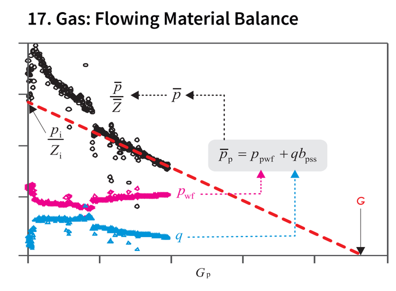
$$\frac{p_{pi} - p_{pwf}}{q} = \frac{\alpha G_a}{qG} + b_{pss}$$

Note: b_{pss} is the inverse of the productivity index and is constant during boundary-dominated flow.

16. Gas: Determination of b_{pss}



17. Gas: Flowing Material Balance



Summary:

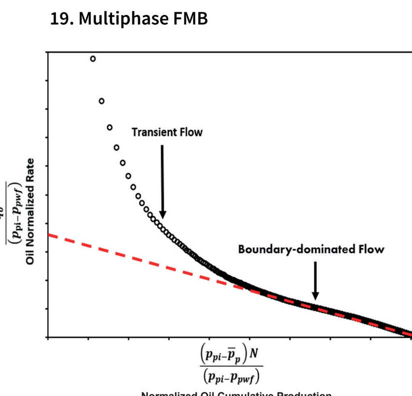
- Use flowing data. No shut-in required.
- Applicable to oil and gas.
- Determines hydrocarbon-in-place, N or G.
- Oil (N): Direct calculation.
- Gas (G): Iterative calculation because of pseudo-time.
- Simple yet powerful.
- Data readily available (wellhead pressure can be converted to sandface pressure).
- Supplements static material balance.

18: Process to Determine G

Calculating G is ITERATIVE:
1. Estimate G. Plot $\bar p/Z$ vs. G_p from p_i/Z_i to G.
2. At any time, G_p is known. Determine $\bar p$ at G_p from $\bar p/Z$ plot.
3. Obtain $\bar\mu_g$ and $\bar c_t$ at $\bar p$.
4. Convert t to t_a and p_{wf} to p_{pwf} (see Figures 12 & 14).
5. Determine b_{pss} from Figure 16.
6. Determine $\bar p$ from $\bar p_p = p_{pwf} + qb_{pss}$.
7. Plot $\bar p/\bar Z$ vs. G_p and determine new G.
8. Repeat steps 2-7 until G converges.

Multiphase Flowing Material Balance (FMB) & FMB Model

19. Multiphase FMB



- The multiphase FMB parallels the single-phase analysis but replaces pressure with pseudo-pressure.
- General form of FMB for oil.

$$\frac{q_o}{p_{pi} - p_{pwf}} = \frac{1}{b} - \frac{1}{bN}\frac{(p_{pi} - \bar p_p)}{(p_{pi} - p_{pwf})}N$$

- Definition of pseudo-pressure.

$$p_{pi} - p_{pwf} = \frac{1}{\left(\frac{k(p_i)\cdot k_{roi}}{\mu_{oi}B_{oi}} + R_{vi}\frac{k(p_i)\cdot k_{rgi}}{\mu_{gi}B_{gi}}\right)}\int_{p_{wf}}^{p_i}\left(\frac{k\cdot k_{ro}}{\mu_o B_o} + R_v\frac{k\cdot k_{rg}}{\mu_g B_g}\right)dp$$

$$p_{pi} - \bar p = \frac{1}{\left(\frac{k(p_i)\cdot k_{roi}}{\mu_{oi}B_{oi}} + R_{vi}\frac{k(p_i)\cdot k_{rgi}}{\mu_{gi}B_{gi}}\right)}\int_{\bar p}^{p_i}\left(\frac{k\cdot k_{ro}}{\mu_o B_o} + R_v\frac{k\cdot k_{rg}}{\mu_g B_g}\right)dp$$

- Gas pseudo-pressure is defined similarly.

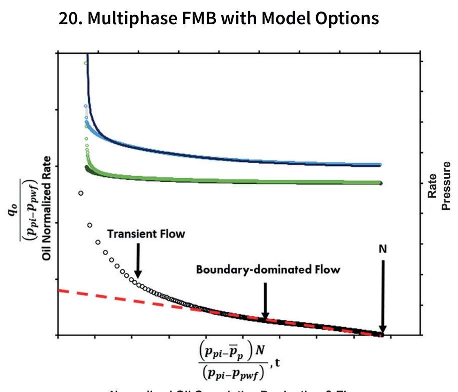
- At any point in time, using the production data, the k_rg / k_ro and k_rw / k_ro ratios are determined from:

$$\frac{k_{rg}}{k_{ro}}(S_g, S_o) = \left(\frac{GOR - R_s}{1 - R_v GOR}\right)\frac{\mu_g B_g}{\mu_o B_o}$$

$$\frac{k_{rw}}{k_{ro}}(S_o, S_w) = WOR\,\frac{\mu_w B_w}{\mu_o B_o}$$

The FMB model generates synthetic average pressure, flowing pressure, and rate for additional history-matching capabilities

20. Multiphase FMB with Model Options



Radial Typecurves

21. Calculations for Oil (Agarwal-Gardner Typecurves)

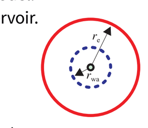
$$k = \frac{141.2B_o\mu_o}{h}\left(\frac{q/\Delta p}{q_D}\right)_{match}$$

$$r_{wa} = \frac{\sqrt{\frac{0.00633k}{\pi\phi\mu_o c_t}\left(\frac{t_c}{t_{DA}}\right)_{match}}}{(r_{eD})_{match}}, \quad s = \ln\left(\frac{r_w}{r_{wa}}\right)$$

$$r_e = \sqrt{\frac{0.00633k}{\pi\phi\mu_o c_t}\left(\frac{t_c}{t_{DA}}\right)_{match}}, \quad N = \frac{\pi r_e^2\phi h S_{oi}}{B_{oi}}$$

Radial Flow Model: Typecurve Analysis

All radial flow typecurves are based on the same reservoir model:
- The well is in the center of a cylindrical homogeneous reservoir.
- No-flow outer boundary.
- Skin factor represented by r_{wa}.
- Information content for all typecurves is the same (see Figures 23 - 30).
- The shapes are different because of different plotting formats.
- Each format represents a different "look" at the data and emphasizes different aspects.



22. Calculations for Gas (Agarwal-Gardner Typecurves)

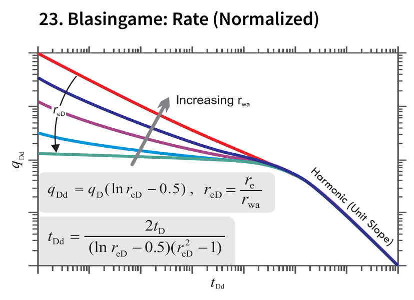
$$k = \frac{1.417\times10^6 T}{h}\left(\frac{q/\Delta p_p}{q_D}\right)_{match}$$

$$r_{wa} = \frac{\sqrt{\frac{0.00633k}{\pi(\phi\mu_g c_t)_i}\left(\frac{t_{ca}}{t_{DA}}\right)_{match}}}{(r_{eD})_{match}}, \quad s = \ln\left(\frac{r_w}{r_{wa}}\right)$$

$$r_e = \sqrt{\frac{0.00633k}{\pi(\phi\mu_g c_t)_i}\left(\frac{t_{ca}}{t_{DA}}\right)_{match}}, \quad G = \frac{\pi r_e^2\phi h S_{gi}}{B_{gi}}$$

Note: Gas calculations are *iterative* because of pseudo-time.

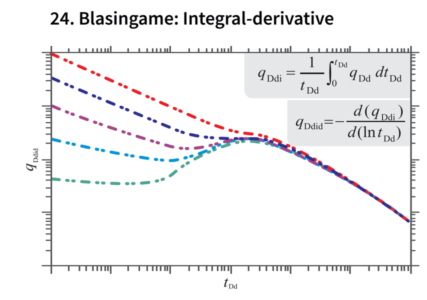
23. Blasingame: Rate (Normalized)



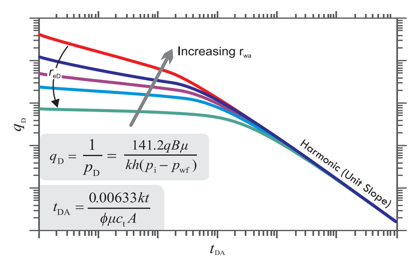
Blasingame

- q_{Dd} and t_{Dd} definitions are similar to Fetkovich.
- Normalized rate ($q/\Delta p$ or $q/\Delta p_p$) is ploted.
- Three sets of typecurves:
  1. q_{Dd} vs. t_{Dd} (see Figure 23).
  2. Rate integral (q_{Ddi}) vs. t_{Dd} (has the same shape as q_{Dd}).
  3. Rate integral-derivative (q_{Ddid}) vs. t_{Dd} (see Figure 24).
- In general: $q_{Dd} = q_D\, b_{Dpss}$, $t_{Dd} = \frac{2\pi}{b_{Dpss}}t_{DA}$.
- b_{Dpps} is a constant for a particular well / reservoir configuration.

24. Blasingame: Integral-derivative



25. Agarwal-Gardner: Rate (Normalized)

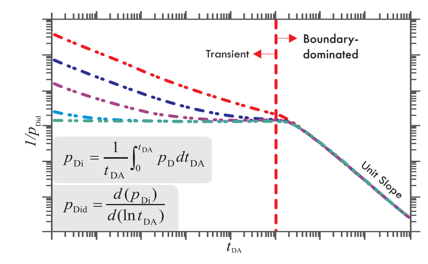


Agarwal-Gardner

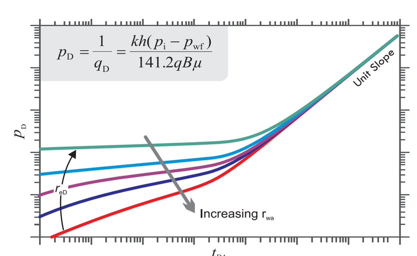
- q_D and t_{DA} definitions are similar to PTA.
- Normalized rate ($q/\Delta p$ or $q/\Delta p_p$) is ploted.
- Three sets of typecurves:
  1. q_D vs. t_{DA} (see Figure 25).
  2. Inverse of pressure derivative ($1/p_{Dd}$) vs. t_{DA} (not shown).
  3. Inverse of pressure integral-derivative ($1/p_{Did}$) vs. t_{DA} (see Figure 26).

Notes:
1. Pressure derivative is defined as $p_{Dd} = \frac{d(p_D)}{d(\ln t_{DA})}$.
2. The inverse of the pressure derivative is usually too noisy, so the inverse of the pressure integral-derivative is used instead.

26. Agarwal-Gardner: Integral-derivative



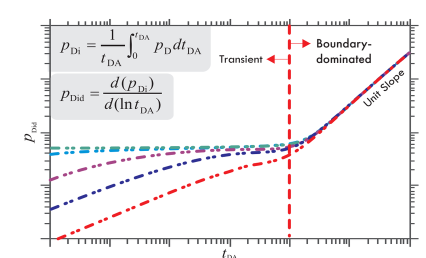
27. NPI: Pressure (Normalized)



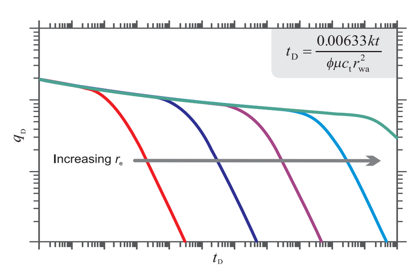
Normalized Pressure Integral (NPI)

- p_D and t_{DA} definitions are similar to PTA.
- Normalized pressure ($\Delta p/q$ or $\Delta p_p/q$) is ploted rather than normalized rate ($q/\Delta p$ or $q/\Delta p_p$).
- Three sets of typecurves:
  1. p_D vs. t_{DA} (see Figure 27).
  2. Pressure integral (p_{Di}) vs. t_{DA} (has the same shape as p_D).
  3. Pressure integral-derivative (p_{Did}) vs. t_{DA} (see Figure 28).

28. NPI: Integral-derivative



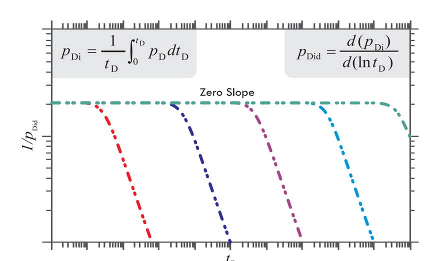
29. Rate (Normalized)



Transient-dominated Data

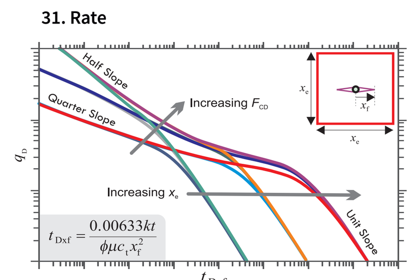
- Similar to Figures 25 & 26 but uses t_D instead of t_{DA} . When most of the data is in *transient* flow, use this format.
- q_D and t_D definitions are similar to PTA.
- Normalized rate ($q/\Delta p$ or $q/\Delta p_p$) is plotted.
- Three sets of typecurves:
  1. q_D vs. t_D (see Figure 29).
  2. Inverse of pressure integral ($1/p_{Di}$) vs. t_D (not shown).
  3. Inverse of pressure integral-derivative ($1/p_{Did}$) vs. t_D. (see Figure 30).

30. Integral-derivative



Fracture Typecurves

31. Rate



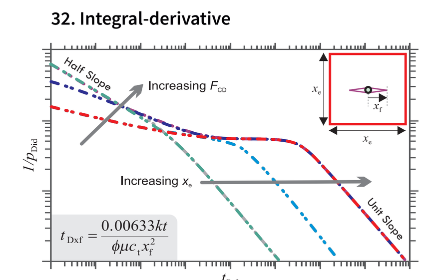
Finite Conductivity Fracture

- Fracture with finite conductivity results in bilinear flow (quarter slope).

- Dimensionless Fracture Conductivity is defined as: $F_{CD} = \frac{k_f w}{kx_f}$.
- Fracture with infinite conductivity results in linear flow (half slope).

- For F_{CD} > 50, the fracture is assumed to have infinite conductivity.

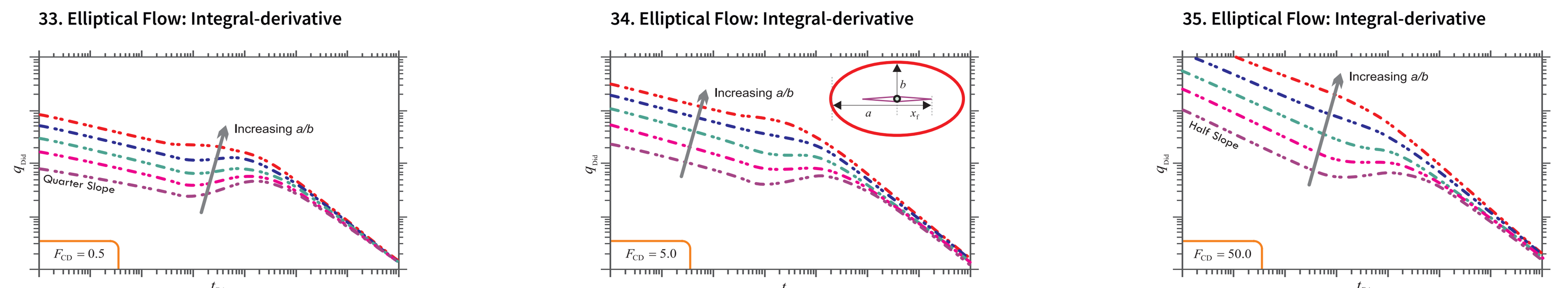
32. Integral-derivative



33. Elliptical Flow: Integral-derivative

34. Elliptical Flow: Integral-derivative

35. Elliptical Flow: Integral-derivative

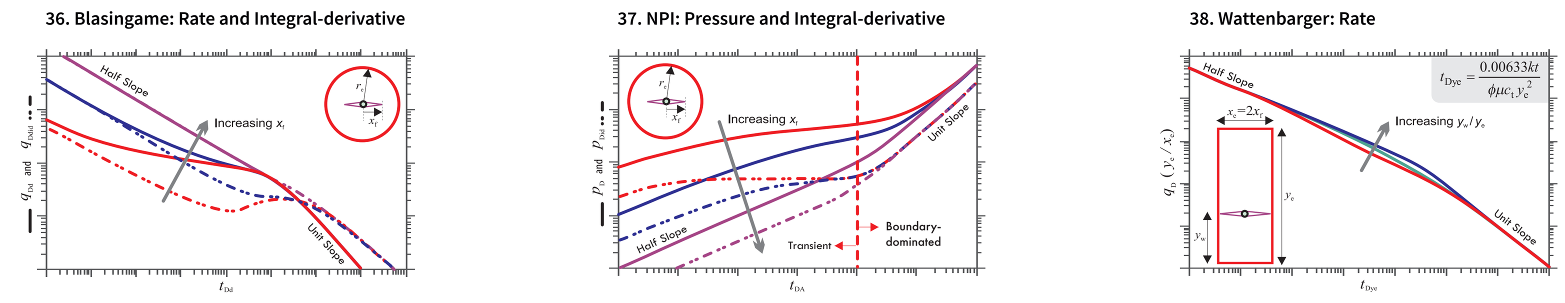


Finite Conductivity Fracture

36. Blasingame: Rate and Integral-derivative

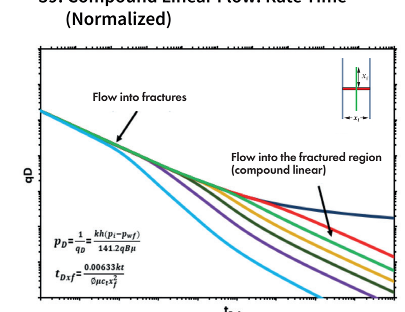
37. NPI: Pressure and Integral-derivative

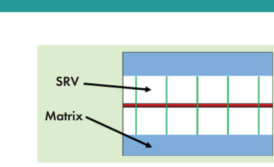
38. Wattenbarger: Rate



Compound Linear Typecurves

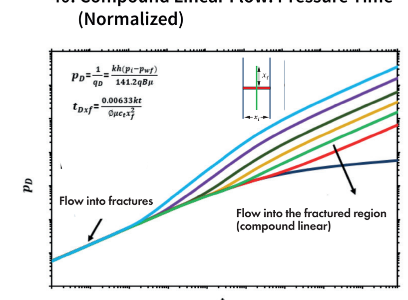
39. Compound Linear Flow: Rate Time (Normalized)





- This typecurve has been developed to account for both first and second (compound) linear flow in multi-fractured horizontal wells.
- The first half slope indicates linear flow into the fractures (inside the SRV), while the second half slope indicates linear flow into the SRV from the matrix. The two half slopes are connected by a transition period. Most production data is expected to fall in the transition flow regime.
- Each unique stem on the typecurve reflects the ratio of x_i/x_f.

40. Compound Linear Flow: Pressure Time (Normalized)

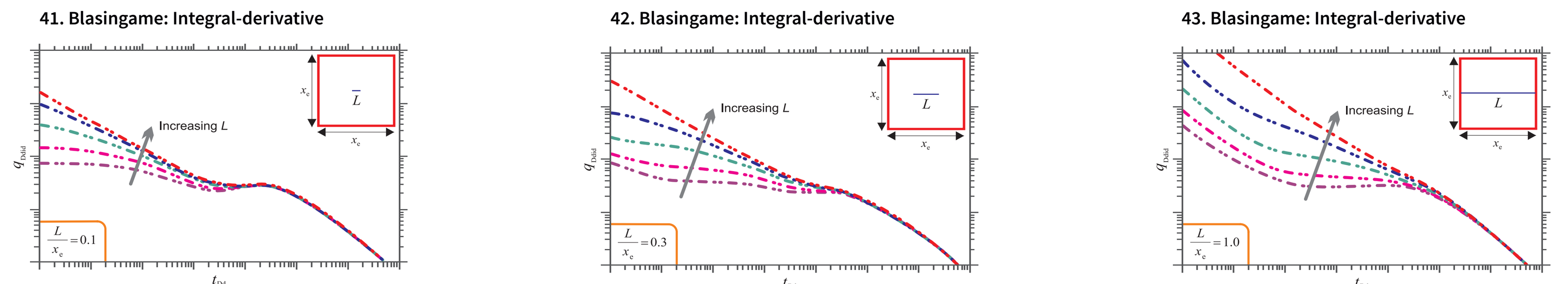


Horizontal Well Typecurves

41. Blasingame: Integral-derivative

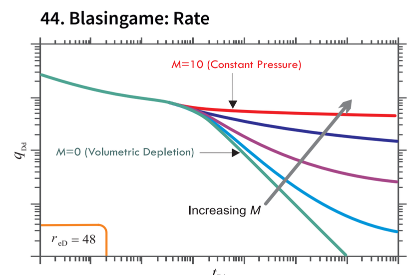
42. Blasingame: Integral-derivative

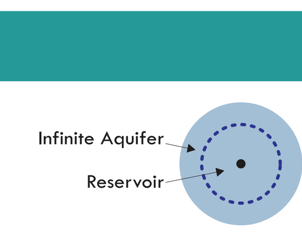
43. Blasingame: Integral-derivative



Water-drive Typecurves

44. Blasingame: Rate



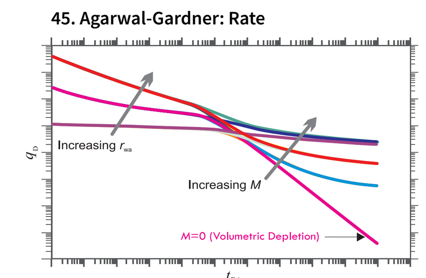


- Mobility ratio (M) represents the strength of the aquifer.

$$M = \frac{k_{aq}}{k_{res}}\frac{\mu_{res}}{\mu_{aq}}$$

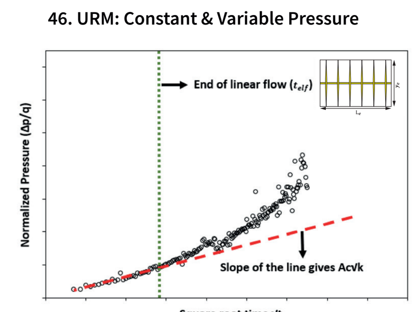
- M = 0 (see Figures 44 - 45) is equivalent to Radial Typecurves (see Figures 23 - 30).

45. Agarwal-Gardner: Rate



Unconventional Reservoir Module (URM)

46. URM: Constant & Variable Pressure



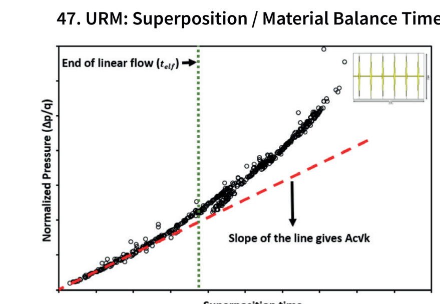
- Used to analyze the first linear flow regime.
- The slope of the analysis line provides A√k .
- The y-intercept can be used to estimate near wellbore productivity loss.
- t_{elf} can be used to estimate the size of the SRV.

For gas:

$$A_c\sqrt{k} = 4\,\frac{200.8\,T}{m}\sqrt{\frac{1}{(\phi\,\mu\,c_t)_i}}$$

Where m is the slope of the analysis line.

47. URM: Superposition / Material Balance Time



Nomenclature

- a semi-major axis of ellipse
- A area
- b semi-minor axis of ellipse
- b_{Dpss} dimensionless parameter
- b_{pss} inverse of productivity index
- B formation volume factor
- B_g gas formation volume factor
- B_{gi} initial gas formation volume factor
- B_o oil formation volume factor
- B_{oi} initial oil formation volume factor
- B_w water formation volume factor
- c_g gas compressibility
- c_t total compressibility
- $\bar c_t$ total compressibility at average reservoir pressure
- F_{CD} dimensionless fracture conductivity
- G original gas-in-place
- G_p gas cumulative production
- G_{pa} pseudo-cumulative production
- h net pay
- k permeability
- k_{aq} aquifer permeability
- k_f fracture permeability
- k_{res} reservoir permeability
- k_{roi} initial oil-relative permeability
- k_{rgi} initial gas-relative permeability
- k_{ro} oil-relative permeability
- k_{rg} gas-relative permeability
- k_{rw} water-relative permeability
- L horizontal well length
- m slope
- M mobility ratio
- N original oil-in-place
- N_p oil cumulative production
- p pressure
- $\bar p$ average reservoir pressure
- p_o reference pressure
- p_D dimensionless pressure
- p_{Dd} dimensionless pressure derivative
- p_{Di} dimensionless pressure integral
- p_{Did} dimensionless pressure integral-derivative
- p_i initial reservoir pressure
- p_p pseudo-pressure
- $\bar p_p$ pseudo-pressure at average reservoir pressure
- p_{pi} initial pseudo-pressure
- p_{pwf} pseudo-pressure at well flowing pressure
- p_{wf} well flowing pressure
- q flow rate
- q_D dimensionless rate
- q_{Dd} dimensionless rate
- q_{Ddi} dimensionless rate integral
- q_{Ddid} dimensionless rate integral-derivative
- q_o oil rate
- Q cumulative production
- Q_{Dd} dimensionless cumulative production
- r_e exterior radius of reservoir
- r_{eD} dimensionless exterior radius of reservoir
- r_w wellbore radius
- r_{wa} apparent wellbore radius
- R_v solution oil-gas ratio
- R_{vi} initial solution oil-gas ratio
- s skin
- S_g gas saturation
- S_{gi} initial gas saturation
- S_{oi} initial oil saturation
- S_w water saturation
- SRV stimulated reservoir volume
- t flow time
- t_a pseudo-time
- t_c material balance time
- t_{ca} material balance pseudo-time
- t_D dimensionless time
- t_{DA} dimensionless time
- t_{Dd} dimensionless time
- t_{Dxf} dimensionless time
- t_{Dye} dimensionless time
- t_{elf} time at end of linear flow
- T reservoir temperature
- w fracture width
- x_e reservoir length
- x_f fracture half length
- x_i half SRV width
- y_e reservoir width
- y_w well location in y-direction
- Z gas deviation factor
- $\bar Z$ gas deviation factor at average reservoir pressure
- Z_i initial gas deviation factor
- α constant
- ϕ porosity
- μ viscosity
- μ_{aq} aquifer fluid viscosity
- μ_g gas viscosity
- $\bar\mu_g$ gas viscosity at average reservoir pressure
- μ_{gi} initial gas viscosity
- μ_o oil viscosity
- μ_{oi} initial oil viscosity
- μ_{res} reservoir fluid viscosity
- μ_w water viscosity

Oil field units; q_g(MMSCFD); t (days)

All analyses described can be performed using IHS Markit's Rate Transient Analysis software Harmony Reservoir

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