The Nuts and Bolts of Falloff Testing

Sponsored by EPA Region 6

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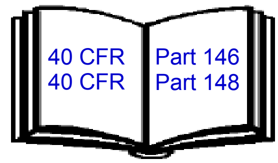
Susie Lopez has a BS in Mechanical Engineering from Oklahoma State University and is a registered Professional Engineer in the State of Oklahoma. Susie has worked with EPA's Ground Water/UIC Section for the past eleven years where she has been involved with the processing of no migration petitions and the review of falloff tests for Class I hazardous waste injection wells. Prior to the EPA, Susie worked with falloff tests for ten years in the oil and gas industry in the production, reservoir, and reservoir simulation engineering aspects of the industry.

What's the Point of a Falloff Test?

- Satisfy regulations



- Measure reservoir pressures
- Obtain reservoir parameters
- Provide data for AOR calculations

1. Both the nonhazardous and hazardous regulations in 40 CFR Part 146 have monitoring requirements that state the Director **shall** require monitoring of the pressure buildup in the injection zone annually, including at a minimum, a shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.§146.13 (Non-haz) / §146.68 (Haz)

   Though the regulations may not directly require a falloff test be conducted for Class II wells, the Director can request additional testing to ensure protection of the USDW.

2. Injection and static reservoir pressure measurements can determine if an endangerment or no migration problem exists

3. Transmissibility value, kh/μ, provides a permeability value for use in the UIC permit and no migration petition demonstrations.

4. These reservoir parameters are used to estimate the maximum pressure buildup in the reservoir for the AOR or ZEI calculations and to support the modeling parameters in a no migration petition.

What’s the Point of a Falloff Test?

- **Characterize injection interval**
- **Identify reservoir anomalies**
- **Evaluate completion conditions**
- **Identify completion anomalies**

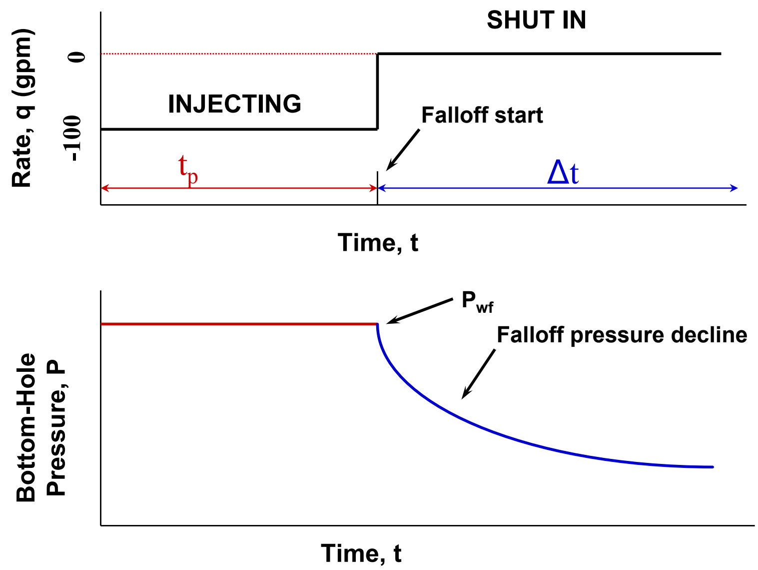
A falloff test can be used to characterize the nature of the injection zone such as indicating if the interval is homogeneous or naturally fractured.

The test may identify reservoir anomalies such as a faults, pinchouts, or boundary from late time data.

The wellbore skin value evaluates the completion condition of the well by indicating if the well is damaged or stimulated, i.e., acidized or frac’d.

Tests can also identify completion anomalies such as partial penetration for a well with wellbore fill or only completed in a portion of a thick sand.

What Is a Falloff Test?



A falloff test is:

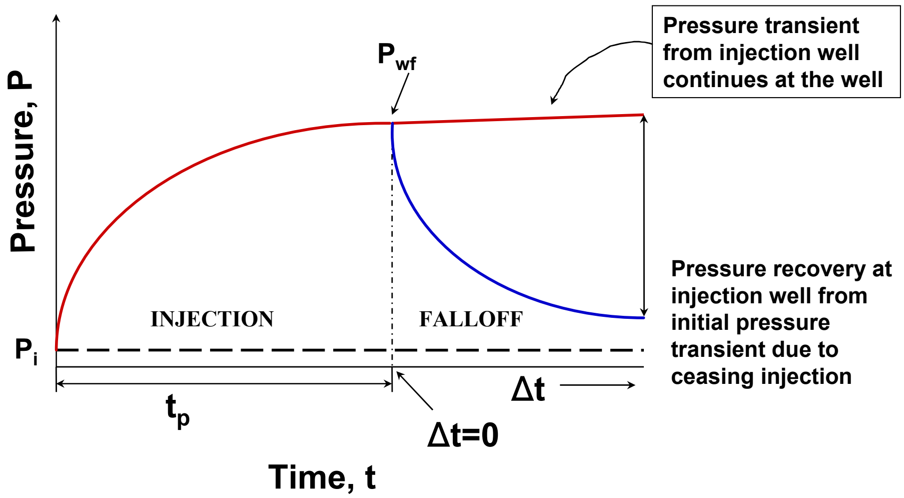
Part of pressure transient theory that involves shutting in an injection well and measuring the pressure falloff

Equivalent to a pressure buildup test in a producing well

Analyzed using the same pressure transient analysis techniques used for buildup and drawdown tests.

A replay of the injection period but is less noisy because there is no fluid going by the pressure gauge.

Effect of Injection and Falloff



Initiating injection creates a pressure transient at the well

Ceasing injection creates another pressure transient at the well

Remember: **RATE CHANGES CAUSE PRESSURE TRANSIENTS**

Pressure Transients

- **Rate changes create pressure transients**
- **Simplify the pressure transients**
  - **Do not shut-in two wells simultaneously**
  - **Do not change the rate in two wells simultaneously**

Rate changes create pressure transients in the reservoir.

It only makes sense to minimize the pressure transients in the reservoir during the test.

Keep the injection rate constant

Do not shut-in two wells simultaneously

Do not change the rate in two wells simultaneously, e.g., shutting in the test well and increasing the rate in an offset well

Always take a good look at an operators falloff testing procedures to confirm multiple pressure transients will not be initiated in the reservoir that could cause a test to be unanalyzable

Falloff Test Planning

Successful welltests require a lot of planning

Several unanalyzable welltests could be prevented with proper planning.

General Planning

- **Most problems are avoidable**
- **Preplanning**
- **Review procedures**

Most problems encountered are within the operator's control and are avoidable such as:

1. Allowing adequate time for both injection and falloff periods to reach radial flow
2. Injecting at a constant rate during the injection period preceding the falloff

Reservoir considerations include an understanding about the type of reservoir you are testing.

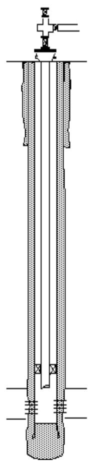
Is it a sandstone or naturally fractured?

Is there only one injection interval or several completed in the well?

If the previous welltest was storage dominated, can the wellbore damage be reduced with stimulation prior to the test?

Carefully review procedures to identify any pitfalls before they occur.

Operational Considerations



- Injection well constraints
  - Type of completion
  - Downhole condition
- Wellhead configuration
  - Pressure gauge installation
  - Shut-in valve

Injection well constraints:

Review the wellbore schematic included with the procedures – if one is not available, get one.

What type of completion does the well have? Perforated, gravel packed, or open hole?

Look at the construction of the well.

Will the downhole condition of the well impact the gauge depth or use of a downhole gauge?

Is there a liner or junk in the hole?

Look to see the wellbore fill depth tagged from the previous RAT.

Wellbore fill can cause partial penetration effects requiring additional time to reach radial flow

How is the wellhead configured?

Is there a crown valve installed so the well won't have to be shut-in to install the pressure gauge?

Is the shut-in valve located near the wellhead? Shut-in the well near the wellhead to minimize the portion of the test dominated by wellbore hydraulics instead of the reservoir.

Operational Considerations

- **Surface facility constraints**
  - **Adequate injection fluid**
  - **Adequate waste storage**
- **Offset well considerations**

Is there adequate injection fluid to maintain a constant injection rate prior to the falloff?

What type of fluid is going to be used for the test?

Plant waste, brine brought in from offsite or a combination of both?

If there is brine brought in, where will it be stored? Frac tanks?

Is there room for the number of frac tanks needed on the well's location?

Is there adequate waste storage for the duration of the falloff test?

Tests are often ended prematurely because of waste storage issues

Offset well considerations

Are there offset wells completed and operating in the same injection interval?

If an offset well is shut-in prior to and during the test, additional waste storage capabilities must be available

If an offset well is not shut-in, a constant injection rate must be maintained both prior to and during the falloff test

Operational Considerations

- **Recordkeeping:**
  - **Maintain an accurate record of injection rates**
  - **Obtain viscosity measurements**

Rule of thumb: At a bare minimum, maintain injection rate data equivalent to twice the length of the falloff

Maintain an accurate record of injection rates

> An adequate rate metering system is a must. If there are rate fluctuations, try to account with them through superposition

The operator should maintain rates on:

> Injection well - prior to shut-in
>
> Offset wells - prior to and during the test

It is also recommended to get viscosity measurements of the injectate to confirm the consistency of the waste injected.

> This is more critical if waste is coming from several different tanks or the test involves a combination of plant waste and brine.

Rule of Thumb: At a bare minimum, maintain injection rate data equivalent to the length of the falloff

Instrumentation

- **Pressure gauges**
  - **Use two**
  - **Calibration**
- **Types of pressure gauges**
  - **Mechanical**
  - **Electronic**
  - **Surface readout (SRO)**
  - **Surface gauge**

Pressure gauges

Use two, one serves as a backup. This backup gauge does not have to be an identical type

Pressure span of the gauge should not grossly exceed expected test pressures

Calibration: The wireline company may haul the same gauge around for years without taking it back to the manufacturer for calibration. Ask to see a copy of the vendor calibration sheet.

Generally, you get what you pay for -

There are several types of pressure gauges that range in price to use

Electronic gauges tend to have a higher resolution than the mechanical gauges

Downhole surface readout (SRO) gauge enables tracking of pressures in real time, but are more expensive than a downhole memory gauge

Surface gauge may be impacted by ambient temperature (sunrise to sunset)

Pressure Gauge Selection

- Selection criteria
  - Wastestream
  - Well goes on a vacuum
  - Wellbore configuration
  - Pressure change at the end of the test
  - Accuracy and resolution

Lots of different factors need to be considered when selecting a pressure gauge:

The wastestream may prevent the use of a downhole gauge.

Surface gauges are insufficient if the well goes on a vacuum.

Junk or casing patch in the hole may prevent the use of a downhole gauge.

The pressure change at the end of the test and the accuracy and resolution of the gauge are dependent of each other. The gauge resolution must be sufficient to measure the pressure changes anticipated at the end of the test.

Ideally, the maximum test pressure should be at least 50% of the gauge pressure limit.

Example: Pressure Gauge Selection

- **What pressure gauge is necessary to obtain a good falloff for the following well?**
  - **Operating surface pressure: 500 psia**
  - **Injection interval: 5000’**
  - **Specific gravity of injectate: 1.05**
  - **Past falloff tests have indicated a higher permeability reservoir of 500 md**
  - **Injection well goes on a vacuum toward the end of the test**
  - **Expected rate of pressure change during radial flow portion of the test is 0.5 psi/hr**

Example: Pressure Gauge Selection

- **Calculate the flowing bottomhole pressure**

500 psi+(0.433 psi/ft)(1.05)(5000) = 2773 psi (neglect tubing friction)

- **Pick a downhole pressure gauge type and range**
  - **2000 psi gauge is too low**
  - **5000 and 10,000 psi gauges may both work**
  - **Resolution levels:**
    - **Mechanical gauge - 0.05% of full range**
    - **Electronic gauge - 0.0002% of full range**

Mechanical gauge:

5000(0.0005) = 2.5 psi   10,000(0.0005)= 5 psi

Electronic gauge:

5000(0.000002)=.01 psi   10,000(0.000002)=.02 psi

In this example, the mechanical gauges do not provide enough resolution for the 0.5 psi/hr anticipated pressure change at the end of the test

Both the 5000 and 10,000 psi electronic gauges provide adequate resolution

The 5000 psi electronic gauge is a better pick because more of the full range of the gauge is used

Falloff Test Design

- **Questions that must be addressed:**
  - **How long must we inject?**
  - **How long do we shut-in?**
  - **What if we want to look for a boundary?**
- **Radial flow is the basis for all pressure transient calculations**
  - **Confirm that the test reaches radial flow during both the injection and falloff periods**

1. Besides the practical aspects of planning a falloff, there is also a theoretical side to falloff test planning
2. Some preliminary assumptions and calculations are needed to answer these theoretical questions
3. If possible, simulate the falloff test using the assumed parameters

Falloff Test Design considerations must address these questions:

The radial flow portion of the test is the basis for all pressure transient calculations

The ultimate goal of the test design is to reach radial flow during both the injection and falloff portions of the test because the falloff is a replay of the injection. If the injection period did not reach radial flow, neither will the falloff.

Falloff Test Design

- The radial flow period follows the wellbore storage and transition periods
- Wellbore storage: Initial portion of the test governed by wellbore hydraulics
- Transition period: Time period between identifiable flow regimes
- Radial Flow: Pressure response is only controlled by reservoir conditions

When is a test in radial flow?

The radial flow period typically follows a wellbore storage and transition period

Wellbore storage is the initial portion of the test when the pressure response at the well is governed by wellbore hydraulics instead of the reservoir.

A transition period is the time period between identifiable flow regimes.

During radial flow, the pressure response is only controlled by reservoir conditions

Falloff Test Design

- **Falloff is a replay of the injection period**
- **Both the injection period and falloff must reach radial flow**
- **Calculate the time to reach radial flow**
- **Different calculations for the injectivity and falloff portions of the test**

The falloff is a replay of the injection portion of the test so the injection period controls what is seen on the falloff

Therefore, it is necessary to calculate the time to reach radial flow in both the injection and falloff periods

The equations used to calculated the time to reach radial flow are different for the injectivity and falloff portions of the test

Time to Radial Flow Calculation

- **Wellbore storage coefficient, C in bbl/psi**
  - **Fluid filled well:**

$$C = V_w \cdot c_{waste}$$

Based on fluid filled wellbore so that pressure is maintained at the surface throughout the duration of the test

  - **Well on a vacuum:**

$$C = \frac{V_u}{\frac{\rho \cdot g}{144 \cdot gc}}$$

Falling fluid level in the wellbore so that the well goes on a vacuum at the surface

Empirical, back of the napkin type, equations can be used to calculate the time to radial flow, though simulating the test is best.

To calculate the time to reach radial flow, first estimate the wellbore storage coefficient, C:

The calculation for C is different for wells with positive surface pressure and wells on a vacuum

V_w= Total wellbore volume, bbls

c_w=fluid compressibility, psi^{-1}

V_u=Wellbore volume per unit length, bbls/ft

Time to Radial Flow Calculation

- **Small C: The well is connected with the reservoir within a short timeframe if the skin factor is not excessively large**
- **Large C: A longer transition time is needed for the well to display a reservoir governed response**

These empirically derived equations can be used with limitations:

If C is small, the well is hooked up with the reservoir within a short timeframe if the skin factor is not excessively large

If C is large, a longer transition time is needed for the well to respond to changes in the reservoir

Some carbonate reservoirs contain vugs which cause larger C values

C can be minimized by a downhole shut-in

High skin also prolongs wellbore storage

Time to Radial Flow Calculation

- **Calculate the time to reach radial flow for an injectivity test:**

$$t_{radial\ flow} > \frac{(200000 + 12000\,s)\cdot C}{\frac{k \cdot h}{\mu}} \qquad hours$$

- **Calculate the time to reach radial flow during the falloff test:**

$$t_{radial\ flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\frac{k \cdot h}{\mu}} \qquad hours$$

- **Note the skin factor,s, influences the falloff more than the injection period**

Example Radial Flow Calculation

- **What injection and falloff timeframes are necessary to reach radial flow given the following injection well conditions?**
- **Assumptions:**
  - **Well maintains a positive wellhead pressure**

Parameters:

Reservoir	**Wellbore**
h=120 ft	7” tubing (6.456” ID)
k=50 md	9 5/8” casing (8.921” ID)
s=15	Packer depth: 4000’
μ=.5 cp	Top of the injection interval: 4300’
c_w=3e-6 psi^{-1}	

High speed example:

Example Radial Flow Calculation

- **Calculate wellbore volume, V_w:**
  - **tubing volume + casing volume below packer**

$$V_w = \left[\pi\left(\frac{6.456}{2\cdot 12}\right)^2(4000) + \pi\left(\frac{8.921}{2\cdot 12}\right)^2(300)\right]\left(\frac{1\,bbl}{5.615\ ft^3}\right) = 185.1\,bbls$$

- **Calculate wellbore storage coefficient, C**
  - **$C=V_w c_w$**

$$C = 185.1\,bbls \cdot \frac{3x10^{-6}}{psi} = 5.5x10^{-4}\,\frac{bbl}{psi}$$

Note: assume the wellbore storage coefficient is the same for both the injection and falloff periods

Value of C is small because the well starts fluid filled and the compressibility and storage coefficients are small.

Example Radial Flow Calculation

- **Calculate minimum time to reach radial flow during the injection period, $t_{radial\ flow}$**

$$t_{radialflow} > \frac{(200000 + 12000\ s)\cdot C}{\frac{k\cdot h}{u}} \qquad hours$$

$$t_{radialflow} > \frac{(200000 + 12000\cdot 15)\cdot 5.5x10^{-4}}{\frac{50\cdot 120}{0.5}} = 0.017\ hours$$

- **Note: The test should not only reach radial flow, but also sustain a timeframe sufficient for analysis of the radial flow period**

Time to radial flow occurs quickly because of the small C and small skin of 15.

If a well is on a vacuum, C could be 2 orders of magnitude larger and the resulting time to radial flow would be much greater.

Note: The test should not only reach radial flow, but also sustain a timeframe sufficient for analysis of the radial flow period

Example Radial Flow Calculation

- **Calculate minimum time to reach radial flow during the falloff, $t_{radial\ flow}$**

$$t_{radial\ flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\frac{k \cdot h}{\mu}} \qquad hours$$

$$t_{radial\ flow} > \frac{170000 \cdot 5.5x10^{-4} \cdot e^{0.14(15)}}{\frac{50 \cdot 120}{0.5}} = 0.064 \ \ hours$$

- **Use with caution!**
  - **This equation tends to blow up in large permeability reservoirs or wells with high skin factors**

Time to radial flow is still short, but notice the falloff time is 4 times the time to radial flow calculated for the injection period

Use with caution! This equation tends to blow up in large permeability reservoirs or wells with high skin factors

Additional Test Design Criteria

- Decide on the test objectives
  - Completion evaluation
  - Determining the distance to a fault
  - Seeing "x" distance into the reservoir

Note: Equations for transient test design are discussed in detail in SPE 17088 provided in the reference portion of this presentation

Define Test Objectives:

Completion evaluation: Test must reach radial flow to calculate the skin factor which indicates the condition of the well

Determining the distance to a fault

Seeing "x" distance into the reservoir. Use radius of investigation to calculate time.

Note: Equations for transient test design are discussed in detail in SPE 17088 provided in the reference portion of this presentation

Additional Test Design Criteria

- **Type of test:**
  - **Falloff**
  - **Multi-rate**
  - **Interference test**
- **Simulate the test**
- **Review earlier test data if available**

Determine the type of test needed to produce analyzable results

Falloff, multi-rate, or interference test

The best approach is to simulate the test using estimated parameters

It is easy to conduct sensitivity cases to evaluate the effects of varying reservoir parameters in simulated tests

Review earlier test data if available

If the test wasn't good the previous year, find out if changes have been made to the procedure or well for the operator to predict the results will be different this year.

Falloff Test Design

- What if no falloff data is available?
  - Review the historical well pressure and rate data
  - Look for "pressure falloff" periods when the well was shut-in
  - This information *may* provide some information that can be used to design the falloff test

Data Needed To Analyze a Falloff

- **Time and pressure data**
- **Rate history prior to the falloff**
- **Basic reservoir and fluid information**
- **Wellbore and completion data**

Time and pressure data:

Surface or bottomhole pressure

Impacted by the gauge type - "Get what you pay for"

Rate history prior to the falloff

Include rate history of offset injection or production wells completed into the same interval

Basic reservoir and fluid information

Viscosity, porosity, compressibility, thickness

Wellbore and completion data

Wellbore radius, r_w

Perforated, gravel packed, open hole

Time and Pressure Data

- **Record sufficient pressure data**
  - **Consider recording more frequently earlier in test**
  - **Consider plotting data while test is in progress to monitor the test**

Record sufficient pressure data to analyze

Consider recording more frequently earlier in test

> More frequent data with an electronic gauge generally provides a better quality derivative curve

Consider plotting data while test is in progress to monitor the test

Operators with waste storage issues may have to end the test prematurely. Result from poor planning.

Reservoir Parameters

- net thickness (h)
  - well log and cross-sections
- permeability (k)
  - core data and previous well tests
- porosity (ϕ)
  - well log or core data
- viscosity of reservoir fluid (μ_f)
  - direct measurement or correlations
- total system compressibility (c_t)
  - correlations, core measurement, or well tests

Injectate Fluid

- viscosity of waste (μ_w)
  - direct measurement or correlation
- specific gravity (s.g.)
  - direct measurement
- rate (q)
  - direct measurement

Rule of thumb: No q, no k

No q – no k

"Quick" Falloff Planning Checklist

- Wellbore construction - depths, dimensions, configuration, obstructions, fill depth
- Injectivity period – constant rate if possible, record rate history, sufficient test duration, waste storage capacity
- Falloff period – time and pressure data, rate history, sufficient test duration, waste storage capacity

Checklist (cont.)

- **Instrumentation – resolution, surface vs. bottomhole gauges, backup gauge**
- **General reservoir and waste information – h, ϕ, c_t, μ_f, μ_{waste}**
- **Area geology – boundaries, net thickness trends, sandstone or carbonate formation**

Pressure Transient Theory Overview

- P-T theory correlates pressures and rates as a function of time
- P-T theory is the basis for many types of well tests
- Used in petroleum engineering, groundwater hydrology, solution mining, waste disposal, and geothermal projects

Pressure Transient Theory

- Involves working the problem backwards:
  - From the measured pressure response, determine the reservoir parameters
  - Start at the wellbore
  - Work out to the reservoir boundaries

Pressure Transient Theory

- Start with what you know:
  - Well and completion history
  - Geology
  - Test conditions
- Pressure responses show dominant features called flow regimes

P-T Theory Applied to Falloffs

- Falloff testing is part of P-T theory
- Falloff tests are analyzed in terms of flow models
- Flow models are solutions to the flow equations

P-T Theory Applied to Falloffs (cont.)

- **The starting point is a partial differential equation (PDE)**
- **The PDE is solved for a variety of boundary conditions**
- **The solution allow calculation of pressure or rate as a function of time and distance**

Partial Differential Equation (PDE)

For Non-Steady State Flow, the PDE, is:

$$\frac{\partial^2 P}{\partial r^2}+\frac{1}{r}\cdot\frac{\partial P}{\partial r}=\frac{1}{0.000264}\cdot\frac{\phi\cdot\mu\cdot c_t}{k}\cdot\frac{\partial P}{\partial t}$$

This equation assumes an infinite, homogeneous, isotropic reservoir with a slightly compressible fluid

c_t, k, ϕ, μ, are independent of P

What's the Point of the PDE?

- Why do we need all these equations and assumptions?
  - Provide an injection well behavior model
  - Provide a method for reservoir parameter evaluation
  - Only work during radial flow

How Do We Solve the PDE?

- **Assume conditions to solve the PDE and obtain a model**
- **Typical constraints:**
  - **At the well**
    - **Finite wellbore radius**
    - **Constant rate injection**
  - **Away from the well**
    - **Infinite-acting**
    - **Uniform reservoir properties and initial pressure**

Solution to the PDE

- **The exact solution to the PDE is in terms of cumbersome Bessel functions**
- **Fortunately an approximate solution based on the exponential integral (Ei) gives almost identical results:**

$$P = P_i + 70.6\,\frac{q \cdot B \cdot \mu}{k \cdot h} \cdot Ei\left(\frac{-948 \cdot \phi \cdot \mu \cdot c_t \cdot r_w^2}{k \cdot t}\right)$$

where:

$$Ei(-x) = -\int_x^{\infty} \frac{e^{-u}}{u}\,du$$

Simplifying the PDE Solution

- **Ei functions:**
  - **tabulated and easy to use**
  - **valid until boundary effects occur**
  - **give the pressure in the reservoir as a function of both time and distance from the well center**
  - **simplified with a log approximation:**

$$Ei = \ln(1.781 \cdot x)$$

- **This leads us to our flow model for falloff analysis:**

Simplifying the PDE Solution

$$P_{wf} - P_i = \left(\frac{141.2 \cdot q \cdot B_w \cdot \mu}{k \times h}\right) \cdot (P_D + s)$$

where:

$$P_D = -\frac{1}{2} \cdot Ei\left[-\frac{r_D^2}{4 \cdot t_D}\right] \cong \frac{1}{2} \cdot \left\{\ln\left[\frac{t_D}{r_D^2}\right] + 0.809\right\}$$

$$t_D = \frac{0.0002637 \cdot k \cdot t}{\phi \cdot \mu \cdot c_t \cdot r_w^2} \qquad r_D = \frac{r}{r_w}$$

Note the use of dimensionless variables, P_D, t_D, and r_D

Predicting Injection Well Pressure Using the PDE Solution

- **Example: Estimate the pressure of an injection well located in an infinite acting reservoir with no skin (s=0). The well has injected 100 gpm for 2 days. Other reservoir data are:**
  - **P_i = 2000 psi**
  - **k = 200 md**
  - **μ = 0.6 cp**
  - **ϕ = 30 %**
  - **h = 50 ft**
  - **B_w = 1 rvb/stb**
  - **c_t = 6e-6 psi^{-1}**
  - **r_w = 0.4 ft**

$$q = \left(\frac{100\,gal}{\min}\right)\left(\frac{bbl}{42\,gal}\right)\left(\frac{1440\min}{day}\right) = 3428.6\,bpd$$

$$t = (2\,days)\left(\frac{24\,hrs}{day}\right) = 48\,hrs$$

Example (cont.)

First, let's calculate the dimensionless variables: r_D, t_D, and P_D

$$r_D = \frac{r}{r_w}$$

Since we're calculating the pressure at the well $r = r_w$ and $r_D = 1$

$$t_D = \frac{0.0002637 \cdot k \cdot t}{\phi \cdot \mu \cdot c_t \cdot r_w^2}$$

$$t_D = \frac{0.0002637\ (200\ md)(48\ hours)}{(0.3)(.6\ cp)(6e-6\ psi^{-1})(0.4^2\ ft^2)}$$

$$t_D = 14.65x10^6$$

Example (cont.)

Now look up P_D on the graph or calculate P_D from the following equation:

$$P_D \cong \frac{1}{2} \cdot \left\{ \ln \left[\frac{14650000}{1^2} \right] + 0.809 \right\}$$

$$P_D \cong 8.65$$

From Figure C.2 in SPE Monograph 5: at t_D= 14.65x10^6 and r_D=1

$$P_D = 8.5$$

Example (cont.)

At t_D= 1.465x10^7 and r_D=1, P_D= 8.5 (Figure C.2 in SPE Monograph 5)

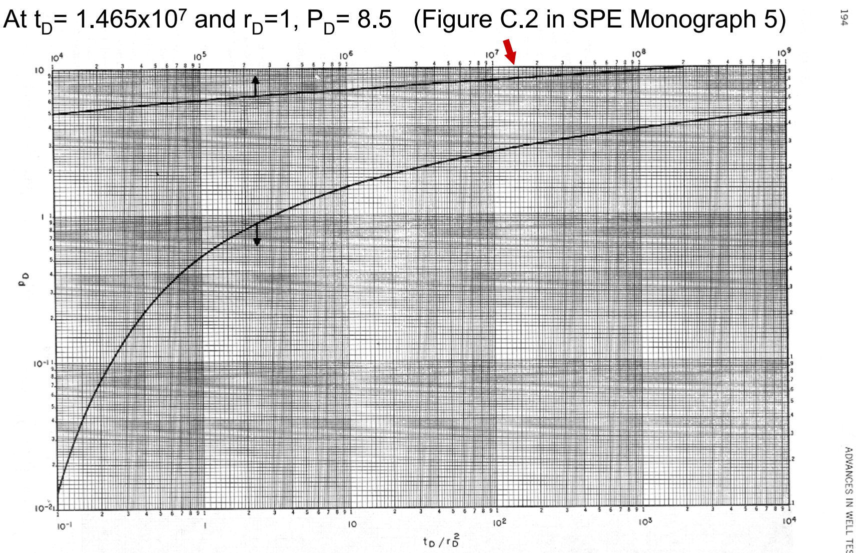


Fig. C.2 Dimensionless pressure for a single well in an infinite system, no wellbore storage, no skin. Exponential-integral solution.

Example (cont.)

Now calculate the pressure increase at the well:

$$P_{wf} - P_i = \left(\frac{141.2 \cdot q \cdot \mathrm{B}_w \cdot \mu}{k \times h} \right) \cdot P_D + s$$

$$P_{wf} - 2000 = \left(\frac{141.2(3428.6)(1)(0.6)}{(200)(50)} \right) \cdot (8.65 + 0)$$

$$P_{wf} = 2251 psi$$

(a pressure increase of 251 psi)

What happens if the injection reservoir isn't infinite?

- Not infinite if limited by a fault or pinchout
- Represent limits as virtual barriers using "image" wells
- A linear PDE means the Ei solutions can be added to consider pressure changes from multiple wells

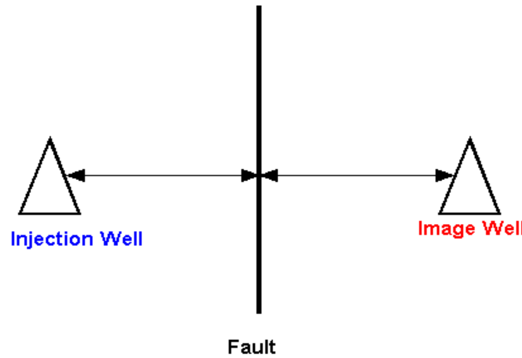
How to Account for Boundary Effects

- **Add the real injector and image well to account for the boundary**
- **1 injector with 1 boundary requires 1 image well**
- **Image wells are more complex with multiple boundaries**

Adding means summing the pressure contribution of each injector

Image wells may have to be mirrored due to the interactions with boundaries

Boundary Effects (cont.)



$$\Delta P_{total} = \Delta P_{(injector\ -\ effect)} + \Delta P_{(fault\ -\ effect)}$$

What happens if the pre-falloff injection rate varies?

- **Again, the PDE is linear**
- **Each rate change creates a new pressure response to be added to the previous response**
- **Account for each rate change by using an image well at the same location**

Use an image well at the same location as the injector with a time delay. Sum the image well pressure contributions.

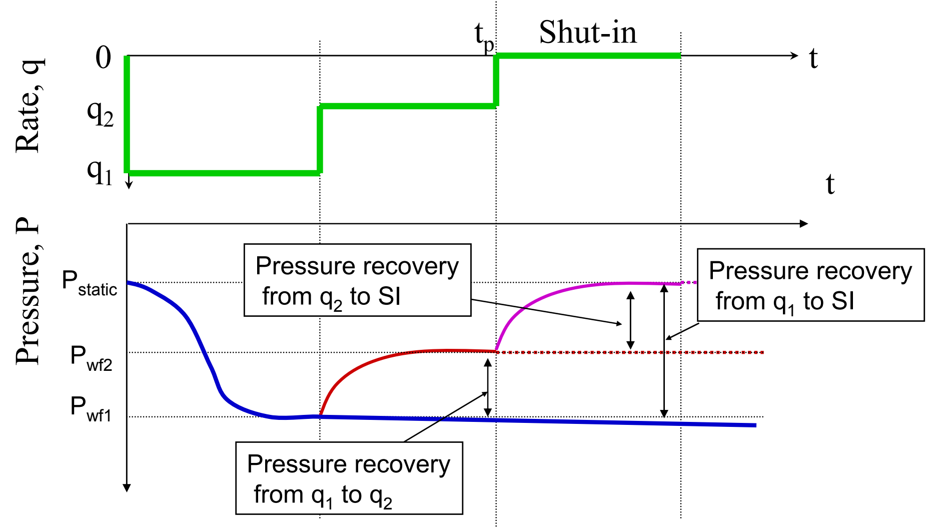
Superposition

Superposition is the method of accounting for the effects of rate changes on a single point in the reservoir from anywhere and anytime in the reservoir including at the point itself using the PDE solution

$$\Delta P_{total} = \Delta P_{injector} + \sum \text{Image well contribution}$$

In dimensionless terms for any point in time, t, the following equation results:

Superposition (cont.)



"Kitchen Sink" Solution to the PDE

- **If we were to account for all wells and potential boundaries (image wells) in a reservoir, the pressure change at any point could be given by:**

$$p(x,y,t) = p_o + \sum_{j=1}^{N} \frac{70.6 q_1^j \mu}{kh} Ei\left(\frac{-39.5\phi\mu c_t \left[(x-x_j)^2 + (y-y_j)^2 \right]}{k\,t} \right)$$

$$+ \sum_{j=1}^{N} \sum_{i=1}^{n_{j-1}} \frac{70.6\left[(q_{i+1}^j - q_i^j)\mu \right]}{k\,h} Ei\left(\frac{-39.5\phi\mu c_t \left[(x-x_j)^2 + (y-y_j)^2 \right]}{k(t-t_i^j)} \right)$$

This is essentially what an analytical reservoir simulator does!

PDE Solution At The Injector

- **The PDE can give the pressure at any reservoir location**
- **At the wellbore, r_D =1, so:**

$$P_{wf} = P_i - \left[\frac{162.6 \cdot q \cdot B \cdot \mu}{k \cdot h}\right] \cdot \left[\log(t) + \log\left(\frac{k}{\phi \cdot \mu \cdot c_t \cdot r_w^2}\right) + 3.23 + 0.87s\right]$$

Use of dimensionless variables can be useful for AOR calculations

Note: This leads directly to the semilog plot

Semilog Plot

- **Applies only during radial flow!**
- **Write PDE solution as a straight line equation with a slope and intercept:**

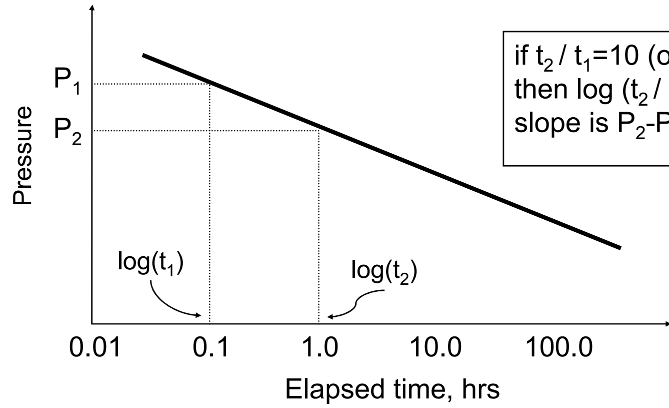
$$P_{wf} = m \cdot \log(t) + P_{1hr}$$

Where m is the semilog plot slope:

$$m = -\frac{162.6 \cdot q \cdot B_w \cdot \mu}{k \cdot h}$$

By grouping the slope and intercept terms together, the solution to the PDE can be written in the following form which is the basis for a semilog plot

Finding the Semilog Slope, m



if t_2 / t_1=10 (one log cycle), then log (t_2 / t_1) = 1 and the slope is P_2-P_1

$$\text{slope} = \frac{\Delta P}{\Delta \log(\Delta t)} = \frac{P_2 - P_1}{\log(t_2) - \log(t_1)} = \frac{P_2 - P_1}{\log\left(\dfrac{t_2}{t_1}\right)}, \quad \text{psi / log cycle}$$

The Many Faces of the Semilog Plot

- **4 semilog plots typically used:**
  - **Miller Dyes Hutchinson (MDH) Plot**
    - **Pressure vs log Δt**
  - **Horner Plot**
    - **Pressure vs log $(t_p + \Delta t)/\Delta t$**
  - **Agarwal Time Plot**
  - **Superposition Time Plot**

There are four different semilog plots typically used in pressure transient and falloff test analysis

MDH

Horner

Agarwal uses equivalent time- Pressure vs log equivalent time

Pressure vs log superposition time function

Pressure/rate vs log superposition time function

Superposition

Miller Dyes Hutchinson (MDH) Plot

- **Applies to wells that reach pseudo-steady state during injection**
  - **Plot pressure vs log Δt**
  - **Means response from the well has encountered all limits around it**
  - **Only applies to very long injection periods at a constant rate**

Δt is the elapsed shut-in time of the falloff

Pseudo-steady state means the response from the well has encountered all the boundaries around the well

Horner Plot

- Plot pressure vs. log $(t_p+\Delta t)/\Delta t$
- Used only for a falloff preceded by a constant rate injection period
- Calculate injecting time, $t_p = V_p/q$ (hours)
  - Where V_p = injection volume since last pressure equalization
  - V_p is often taken as cumulative injection volume since completion
- Caution: Horner time can result in significant analysis errors if the injection rate varies prior to the falloff

Agarwal Time Plot

- Plot pressure vs log equivalent time, Δt_e
  - $\Delta t_e = \log(t_p \, \Delta t)/(t_p + \Delta t)$
    - Where t_p is as defined for a Horner plot
  - Similar to Horner plot
  - Time function scales the falloff to make it look like an injectivity test

Superposition Time

- **Accounts for variable rate conditions prior to a falloff test**
- **Most rigorous semilog analysis method**
- **Requires operator to track rate history**

Rule of thumb: At a bare minimum, maintain injection rate data equivalent to twice the length of the falloff

Calculating Superposition Time Function

- **Superposition time function:**
  - **Can be written several ways – below is for a drawdown or injectivity test:**

$$\Delta t_{sp} = \left[\sum_{j=1}^{n} \left(\frac{q_j - q_{j-1}}{q_n} \right) \log \left[\Delta t - \Delta t_{j-1} \right] \right]$$

- **Pressure function is modified also:**

$$\Delta P_{sp} = \frac{\left(P_{initial} - P_{wf} \right)}{q_n}$$

Which Time Function Do I Use?

- **Depends on available information and software:**
  - If no rate history, use Horner
  - If no rate history or cumulative injection total, use MDH
  - If you have rate history equal to or exceeding the falloff test length, use superposition
  - Horner or MDH plots can be generated in a spreadsheet
  - Superposition is usually done with welltest software

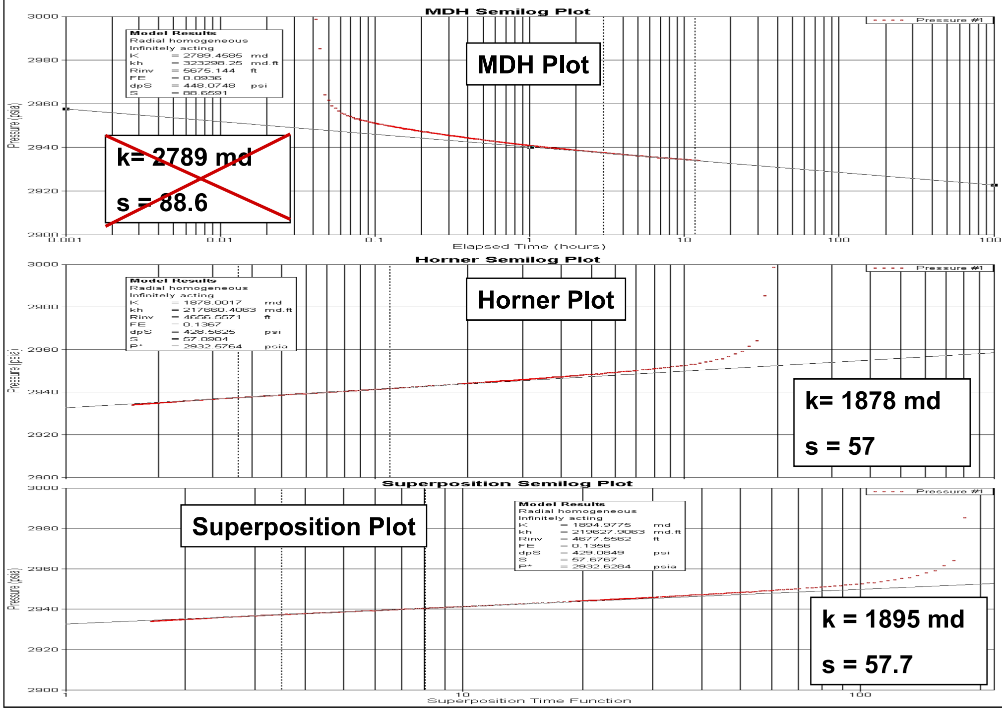
Which Time Function Do I Use?

- Rules of thumb:
  - Use MDH time only for very long injection times (e.g., injector at pseudo-steady state)
  - Use Horner time when you lack rate history or software capability to compute the superposition function
  - Superposition is the preferred method if a rate history is available

Which Time Function Do I Use?

- Horner <u>may</u> substitute for superposition if:
  - The rate lasts long enough to reach the injection reservoir limits (pseudo-steady state)
  - The rate prior to shut-in lasts twice as long as the previous rate
  - At a minimum, the rate prior to shut-in lasts as long as the falloff period
  - Horner is a single rate superposition case

One Falloff Test Plotted with Three Semilog Methods



Other Uses of a Semilog Plot

- Calculate radius of investigation, r_i
- Completion evaluation, skin factor, s
- Skin pressure drop, ΔP_{skin}
- False extrapolated pressure, P^*

Radius of Investigation

- Distance a pressure transient has moved into a formation following a rate change in a well (Well Testing by Lee)
- Use appropriate time to calculate radius of investigation, r_i
  - For a falloff time shorter than the injection period, use t_e or the length of the injection period preceding the falloff to calculate r_i

Radius of Investigation

- **There are numerous equations that exist to calculate r_i in feet**
- **They are all square root equations, but each has its own coefficient that results in slightly different results** **(OGJ, Van Poollen, 1964)**
  - **Square root equation based on cylindrical geometry**

$$r_i = \sqrt{0.00105 \frac{k\,t}{\phi\,\mu\,c_t}} \equiv \sqrt{\frac{k\,t}{948\,\phi\,\mu\,c_t}}$$

From SPE Monograph 1: (Eq 11.2) and Well Testing, Lee (Eq. 1.47)

Skin Factor

- The skin factor, s, is included in the PDE
- Wellbore skin is the measurement of damage near the wellbore (completion condition)
- The skin factor is calculated by the following equation:

$$s = 1.1513\left[\frac{p_{1hr} - p_{wf}}{m} - \log\left(\frac{k\,t_p}{(t_p + 1)\phi\,\mu\,c_t\,r_w^2}\right) + 3.23\right]$$

The equation deviates from the usual equation for skin in that the factor,

$t_p/(t_p+\text{delta } t)$, where delta t = 1 hr, appears in the log term.

Delta t is usually assumed to be negligible, however, for short injection periods this term could be significant

Skin Factor

- Wellbore skin is quantified by the skin factor, s
  - “+” positive value - a damaged completion
    - Magnitude is dictated by the transmissibility of the formation
  - “-” negative value - a stimulated completion
    - - 4 to - 6 generally indicates a hydraulic fracture
    - -1 to - 3 typical acid stimulation results in a sandstone reservoir
    - Negative results in a larger effective wellbore

Effective Wellbore Radius Concept

- Ties the skin factor into an effective wellbore radius (wellbore apparent radius, r_{wa})
- $r_{wa} = r_w e^{-s}$
- A negative skin results in a larger wellbore radius and therefore a lower injection pressure

Effective Wellbore Radius

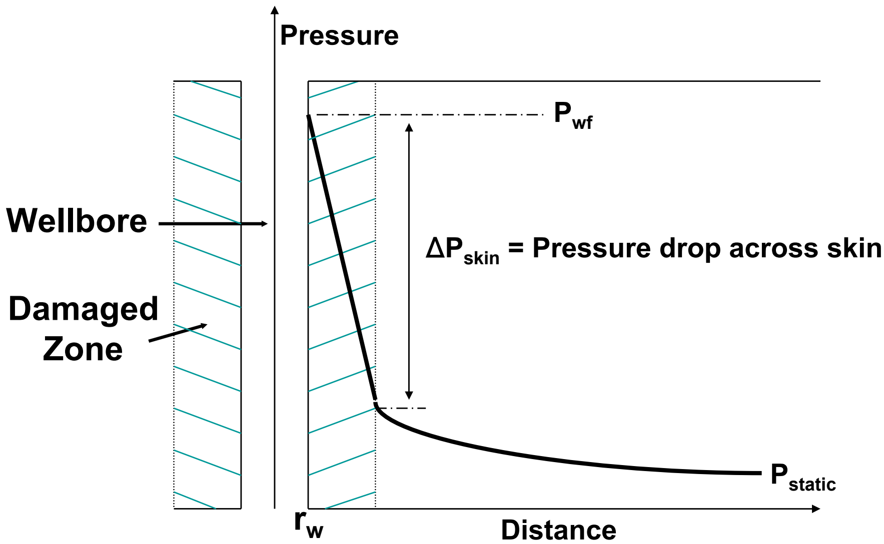
- Example: A well with a radius of 5.5" had a skin of +5 prior to stimulation and –2 following the acid job. What was the effective wellbore radius before and after stimulation?
- $r_{wa} = r_w e^{-s}$

$$r_{wa} = (5.5\,in)\left(e^{-5}\right) = 0.037\,in \quad \textbf{Before}$$

$$r_{wa} = (5.5\,in)\left(e^{-(-2)}\right) = 40.6\,in \quad \textbf{After}$$

- A little bit of skin makes a big impact on the effective wellbore radius

Pressure Profile with Skin Effect



Completion Evaluation

- The assumption that skin exists as a thin sheath is not always valid
  - Not a serious problem in the interpretation of the falloff test
  - Impacts the calculation of correcting the injection pressure prior to shut-in
- Note the term $t_p/(t_p+\Delta t)$, where Δt = 1 hr, appears in the log term and this term is assumed to be 1
  - For short injection periods this term could be significant (DSTs)

Completion Evaluation

- Wellbore skin
  - Increases the time needed to reach radial flow in a falloff
  - Creates a pressure change immediately around the wellbore
  - Can be a flow enhancement or impediment

Completion Evaluation

- Too high a skin may require excessively long injection and falloff periods to establish radial flow
- The larger the skin, the more of the falloff pressure drop is due to the skin

Skin Pressure Drop

- **Skin factor is converted to a pressure loss using the skin pressure drop equation**
- **Quantifies what portion of the total pressure drop in a falloff is due to formation damage**

$$\Delta P_{skin} = 0.868\, m\, s$$

Where,
P_{skin} = pressure due to skin, psi
m = slope of the Horner plot, psi/cycle
s = skin factor, dimensionless

Dependent on the last injection pressure prior to shut-in so an accurate recording of this pressure point is important

Corrected Injection Pressure

- **Calculate the injection pressure with the skin effects removed**

$$P_{corrected} = P_{inj} - \Delta P_{skin}$$

Where:
$P_{corrected}$ = adjusted bottomhole pressure, psi
P_{inj}= measure injection pressure at $\Delta t = 0$, psi
P_{skin} = pressure due to skin, psi

- **$P_{corrected}$ is injection pressure based on pressure loss through the formation only**

False Extrapolated Pressure

- False Extrapolated Pressure, P^*, is the pressure obtained from the semilog time of 1
- For a new well in an infinite acting reservoir, it represents initial reservoir pressure

False Extrapolated Pressure

- For existing wells, it must be adjusted to $\overline{P}$, average reservoir pressure
  - Requires assumption of reservoir size, shape, injection time, and well position within the shape
  - For long injection times, P^* will differ significantly from $\overline{P}$
  - P^* to $\overline{P}$ conversions are based on 1 well reservoirs, simple geometry
- We don’t recommend using P^*
- Use the final measured shut-in pressures, if well reaches radial flow, for cone of influence calculations

Semilog Plot Usage Summary

- A semilog plot is used to evaluate the radial flow portion of the well test
- Reservoir transmissibility and skin factor are obtained from the slope of the semilog straight line during radial flow
- Superposition is used for rate variations

The key to the semilog plot: Semi-log plots are not useful if the test does not reach radial flow.

Identifying Flow Regimes

Flow regimes are characterized by mathematical relationships between pressure, rate, and time.

Flow regimes are a visualization of what goes on in the reservoir

Identifying Flow Regimes

- Create a master **diagnostic** plot, the **log-log plot**
- Log-log plot contains two curves
- Individual flow regimes:
  - Characteristic shape
  - Sequential order
  - Specific separation
- Critical flow regime - **radial flow**

The first plot used to identify flow regimes is the log-log plot.

The log-log plot is a master diagnostic plot that contains two curves, a pressure curve and a derivative curve

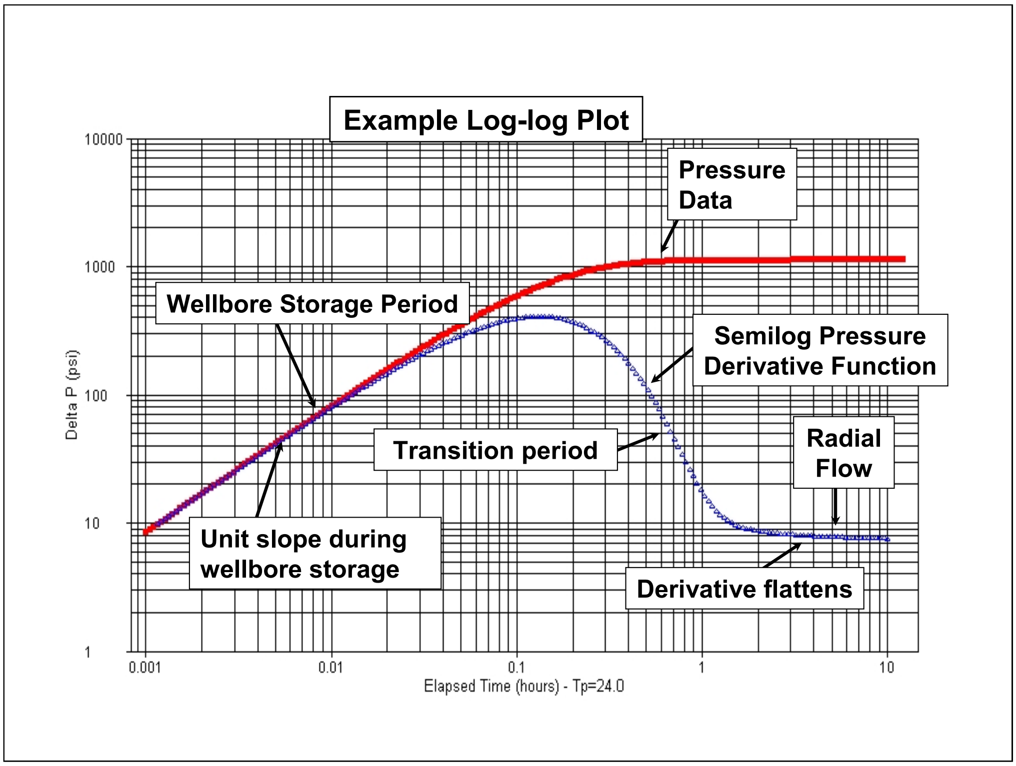
The log-log plot identifies the various stages and flow regimes present in a falloff test

Individual flow regimes have characteristic slopes and a sequential order on the log-log plot with the critical flow regime being radial flow.

The radial flow portion of the log-log plot is identified and then the corresponding timeframe on the semilog plot is used for the calculations

Flow regimes are characterized by specific slopes and trends for P and P', as well as specific separation between the two curves

The radial flow portion is the critical flow regime because it is the portion of the test that the calculations are based



Pressure curve - red

Derivative curve - blue

Wellbore storage period: Pressure and derivative curves overlay on a unit slope

Radial flow: Derivative flattens

Notice the pressure curve flattens prior to radial flow so the pressure curve is not a good indicator of radial flow

Log-log Plot Pressure Functions

Rate variations prior to falloff test determine how the pressure function is to be plotted

- **Constant rate - Plot pressure**
- **Variable rate - Normalize pressure**

Just like the time function, rate variations prior to the shut-in of the well determine how pressure is plotted on the Y axis

Constant rate - Plot pressure

Variable rate - Normalize pressure data or normalize time function using the rates. P/q term

Log-log Plot Time Functions

- **Rate variations prior to shut-in dictate the log-log plot time function:**
  - **Use if the injection rate is constant <u>and</u> the injection period preceding the falloff is significantly longer than the falloff**
  - **Elapsed time, Δt**

As with the semilog plot, rate variations prior to shut-in also dictate the log-log plot time function to use on the log-log plot:

Time function is plotted on the x-axis of the log-log plot

Elapsed time, Δt (Real time)

Calculate as: $\Delta t_{elapsed} = t_{shut\ in} - t_{each\ test\ data\ point}$

Use if the injection rate is constant **<u>and</u>** the injection period preceding the falloff is significantly longer than the falloff

Time function is similar to the time function for the MDH semilog plot.

Log-log Plot Time Functions

- **Agarwal equivalent time, t_e**
  - **Calculate as:** $$t_e = \frac{t_p \, \Delta t}{t_p + \Delta t}$$
  - **Use if the injection period is short**
- **Superposition time function**
  - **Use if the injection rate varied**
    - **Most rigorous time function**

Equivalent time, t_e:

Also referred to as Agarwal equivalent time

Calculate as a Horner time function and should be used if the injection period is short

In this equation, the injection volume since that last stabilization period on the well divided by the injection rate is used to calculate the injecting time, t_P:

$t_p = V_p/q$ (hours)

Where, V_p= injection volume since last pressure equalization

V_p is often mistaken as cumulative injection volume since completion

Superposition Time Function should be used if the injection rate varied prior to shut-in for the falloff and the rate history is available.

The superposition time function is the most rigorous time function – some type of computer software is needed to calculate

Pressure Derivative Function

- **Magnifies small changes in pressure trends**
- **Good recording device critical**
- **Independent of skin**
- **Popular since 1983**

The derivative function is graphed on the log-log plot

The main use of the derivative is to magnify small changes in pressure trends (slope) of the semilog plot to help identify:

Flow regimes

Boundary effects

Layering

Natural fractures (dual porosity)

Derivatives amplify reservoir signatures and noise so the use of a good pressure recording device is critical

The derivative for a specific flow regimes is independent of the skin factor, while the pressure is not

Use of derivative curves have been around since 1983 and are not a new technology

Pressure Derivative Function

- **Combines a semilog plot with a log-log plot**
- **Calculates a running slope of the MDH, Horner, or superposition semilog plots**
- **The logarithmic derivative is defined by:**

$$P' \quad \frac{d\left[P\right]}{d\left[\ln(\Delta t)\right]} \quad \Delta t \cdot \frac{d\left[P\right]}{d\left[\Delta t\right]}$$

The derivative combines a semilog plot with a log-log plot
The derivative is the running slope of the MDH, Horner, or superposition semilog plots of pressure vs log delta t

The derivative function is simply the slope of the semilog plot which is the change in pressure over the change of log delta t

Pressure Derivative Function

- Recent type curves make use of the derivative by matching both the pressure and derivative simultaneously
- A test can show several flow regimes with “late time” responses correlating to distances farther from the wellbore

Plotted on a log-log plot, flow regimes are characterized by specific slopes and trends for P and P', as well as specific separation between P and P'

Use of the pressure and derivative curves provide a better type curve match since two curves are matched instead of just one. The derivative curve also offers more shape to match than the pressure curve.

Pressure Derivative Function

- **Example: For a well in an infinite acting reservoir with radial flow**

$$P_D = 0.5\left(\ln\left[t_D\right] + 0.80907\right)$$

so that

$$P'_D = t_D \cdot \frac{d\left[P_D\right]}{d\left[t_D\right]} = 0.5 \qquad \text{constant value}$$

- **The constant derivative value plots as a "flat spot" on the log-log plot**

When the reservoir is in radial flow, the logarithmic derivative plots at a constant value for all times

The constant derivative value plots as a "flat spot" on the log-log plot

If you use dimensionless variables, the derivative calculates to be 0.5. Dimensionless variables are used for some type curves.

Remember: During radial flow P' plots as a constant value, that is flat

For wellbore storage:

The log-log plot of the derivative will plot the same slope as the pressure curve, and both will have a unit slope

For Linear Flow:

Both the derivative and pressure curves will have the same slope, but the derivative is lower than the pressure curve, usually about a third of a log cycle lower

Pressure Derivative Function

- **Usually based on the slope of the semilog pressure curve**
- **Can can be calculated based on other plots:**
  - **Cartesian**
  - **Square root of time:** $\sqrt[2]{time}$
  - **Quarter root of time:** $\sqrt[4]{time}$
  - **1/square root of time:** $\dfrac{1}{\sqrt[2]{time}}$

Derivative function is usually based on the slope of the semilog plot

However, the derivative can also be based on other specialized plots to make identification of a specific flow regime easier to identify

What Flow Regimes Are Active?

- **Examine what might happen in and near the wellbore to determine early time behavior**
- **Examine the reservoir geology, logs, etc., to determine late time behavior**

When trying to identify flow regimes, recognize the test is first going to see what is happening in or near the well. If the test is not dominated by wellbore hydrualics, i.e. wellbore storage, the test will then observe the reservoir responses away from the well

Always use common sense during the preplanning of the welltest

1. Well completion history – check wellbore fill

The completion condition of the well will dictate the early time behavior

2. The test must get outside the influences of the well prior to and into the reservoir during the lat time behavior of the test. If you want to specifically check for a reservoir anomaly away from the well, these are things that must be considered when planning the test.

Single fault

Multiple boundaries

Layering

Natural Fractures (dual porosity)

Wellbore Storage

- **Occurs during the early portion of the test**
- **Caused by shut-in of the well being located at the surface rather than at the sandface**
  - **After flow - fluid continues to fall down the well after well is shut-in**
  - **Location of shut-in valve away from the well prolongs wellbore storage**

Welbore storage is caused by the well being shut-in at the surface instead of at the sandface.

The length of the wellbore storage period can be impacted by the location of the shut-in valve. Always shut-in the well near the wellhead.

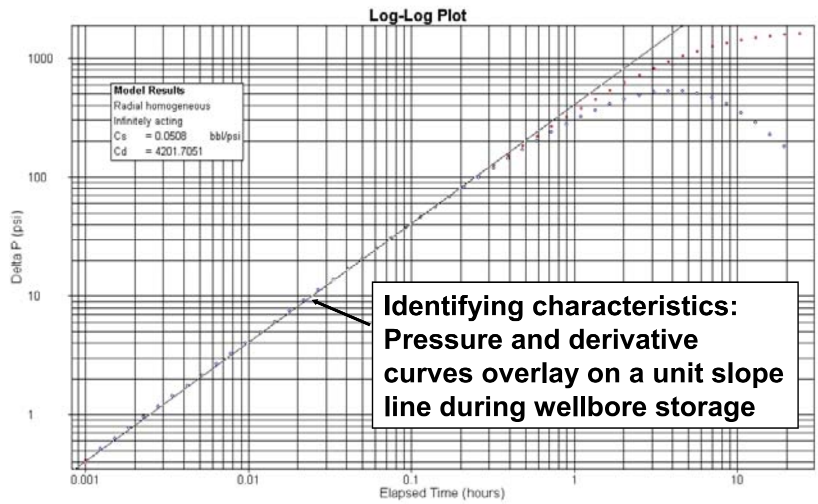
Wellbore Storage

- Pressure responses are governed by wellbore conditions not the reservoir
- High wellbore skin or low permeability reservoir may prolong the duration of the wellbore storage period
- A wellbore storage dominated test is unanalyzable

High wellbore skin or low permeability reservoir results in a slower transfer of fluid from the well to the formation, therefore, extending the duration of the wellbore storage period

If the welltest does not reach radial flow, the test is unanalyzable

Wellbore Storage Log-log Plot



Identifying characteristics of wellbore storage

Unit slope on the log-log plot for both the pressure and derivative curves

Caused by shut-in of the well being located at the surface rather than at the sandface so there is after flow - fluid continues down well after well is shut-in

Wellbore storage can be impacted by where the shut-in valve is located.

During wellbore storage, pressure responses are governed by wellbore conditions and are not representative of reservoir behavior

High wellbore skin or low permeability reservoir results in a slower transfer of fluid from the well to the formation extending the duration of the wellbore storage period

A welltest dominated by storage is unanalyzable

Radial Flow

- The critical flow regime from which all analysis calculations are performed
- Used to derive key reservoir parameters and completion conditions
- Radial flow characterized by a straight line on the semilog plot
- Characterized by a flattening of the derivative curve on log-log plot

Radial flow is the ultimate goal of the Falloff Test

Radial Flow

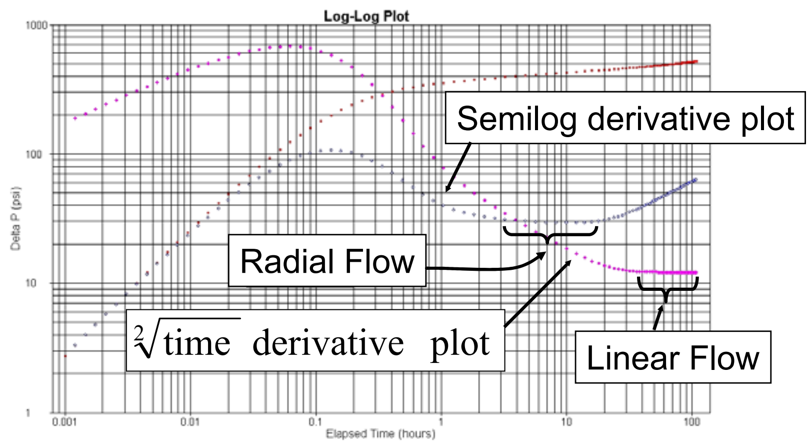
- **A test needs to get to radial flow to get valid results**
- **May be able to obtain a minimum permeability value using the derivative curve on the log-log plot if well does not reach radial flow**
- **Try type curve matching if no radial flow**

Rule of thumb: Leave the well shut-in for an additional 1/3 log cycle after reaching radial flow to have an adequate radial flow period to evaluate

In tests where the derivative did not reach a plateau (i.e. radial flow), some pressure transient computer software packages can estimate a transmissibility from either the log-log plot derivative, by taking an antilog, or using the semilog plot slope. The transmissibility obtained at this point in the test is a minimum because the derivative has not reached its minimum value. The derivative reaches its minimum value at the radial flow plateau, resulting in a smaller slope value and, consequently, a larger transmissibility.

Example: Well in a Channel

- **Well observes linear flow after reaching the channel boundaries**



Two derivative curves are plotted along with the pressure curve:

The pressure curve is shown in red

The blue curve is based on the semilog plot and the magenta curve is based on the square root of time plot.

When the reservoir is in radial flow and infinite acting, the logarithmic derivative of the semilog plot (blue curve) plots at a constant value for all times, that is, the constant semilog derivative value plots as a "flat spot" on the log-log plot

For wellbore storage, both the pressure and semilog derivative plots have a unit slope and overlay each other

For linear flow, a pressure curve and semilog derivative curve will have the same slope, but the derivative curve will be lower, generally about a third of a log cycle lower.

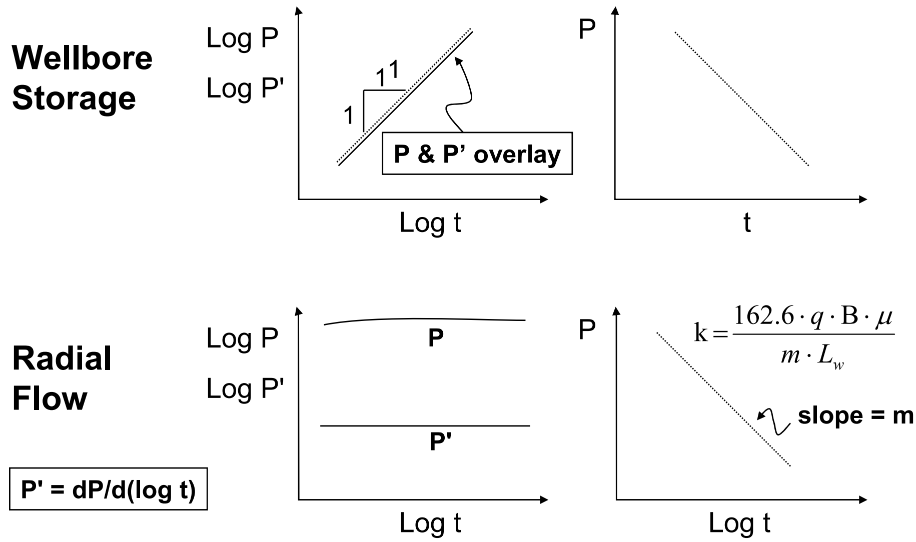
The derivative based on the square root of time is flat when the well is in linear flow. This illustrates the advantages of being capable of plotting the derivative on various time functions

Radial flow – pressure derivative plots as a constant value or as a flat spot in the curve

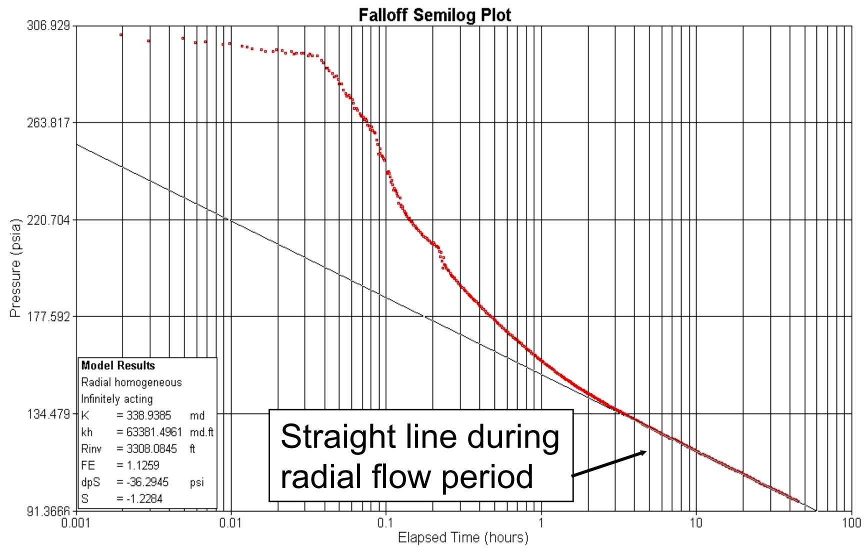
Wellbore storage – pressure and pressure derivative plot as a unit slope

Linear flow – pressure derivative and pressure plot have the same slope, but the derivative is lower

Typical Log-log Plot Signatures

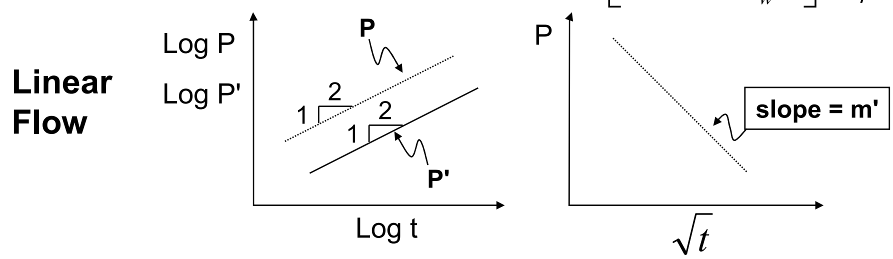


Example SemiLog Plot



Typical Log-Log Plot Signature

$$k = \left[\frac{8.128 \cdot q \cdot B}{h \cdot m' \cdot L_w} \right]^2 \cdot \frac{\mu}{\phi \cdot c}$$



P' = dP/d(log t)

Here's an example of a linear flow regime.

Linear flow regimes may result from: Flow in channel / Parallel faults / Highly conductive hydraulic fracture

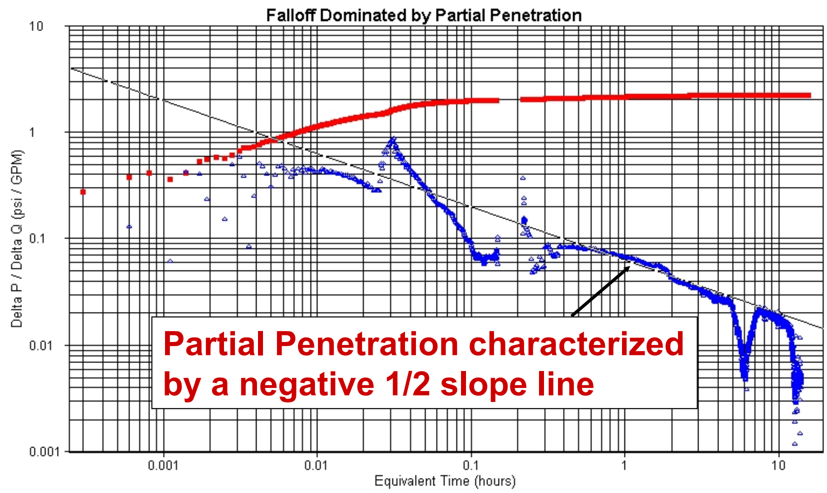
Log-log plot:

Half slope on both the pressure and derivative curves

Derivative curve approximately 1/3 of a log cycle lower than the pressure curve

Square root time plot: Straight line

Log-log Plot Dominated by Spherical Flow



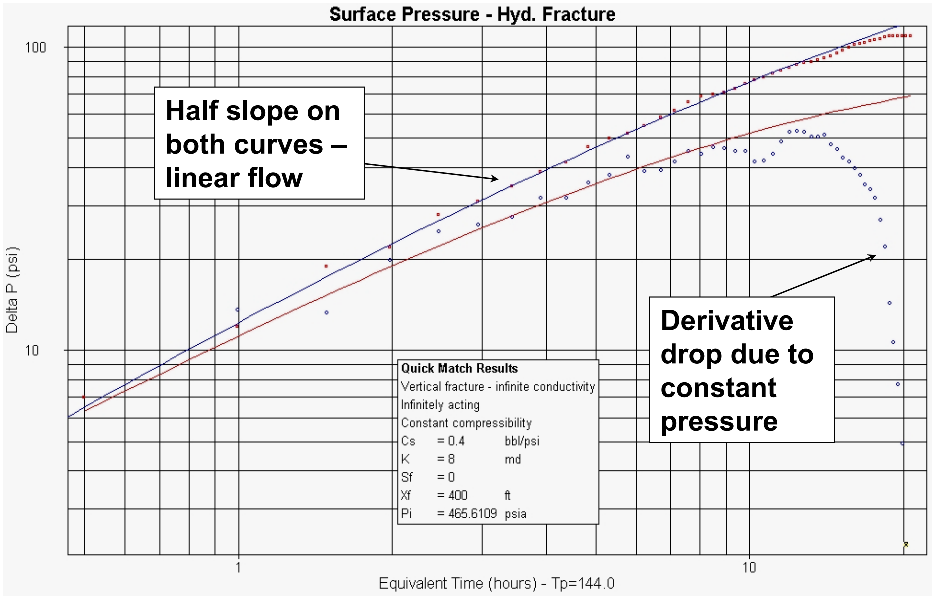
Spherical Flow:

Indicates a partial penetration effect. This is very common with wells having a lot of wellbore fill

Characterized by a derivative negative half slope on the log-log plot

The welltest in this example does not get to radial flow and is therefore not analyzable

Hydraulic Fracture Log-log Plot



Flow regimes:

Wellbore Storage

Fracture Linear Flow

Usually hidden by wellbore storage

Bilinear Flow

Result of simultaneous linear flows in the fracture and from the formation into the fracture

Log-log plot: Quarter slope on both the pressure and derivative curves

Quarter root plot: Straight line

Psuedo-Linear Flow

Follows bilinear flow after a transition period

Log-log plot: Half slope of the derivative curve

Square root time plot: straight line

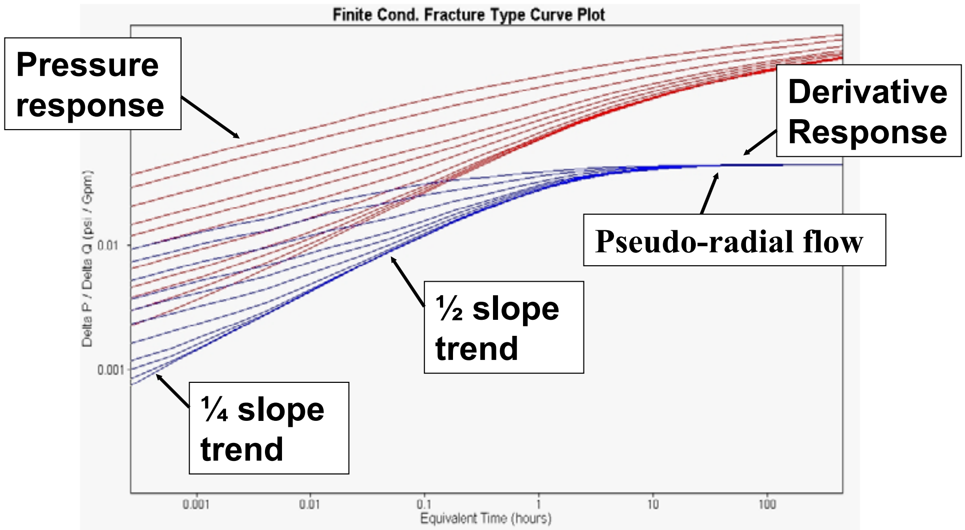
Formation Linear Flow

Linear flow from formation into fractures

Log-log plot: Half slope on both the pressure and derivative plots

Square root time plot: Straight line

Hydraulic Fracture Response



Flow regimes:

Bilinear Flow

Result of simultaneous linear flows in the fracture and from the formation into the fracture

Log-log plot: Quarter slope on both the pressure and derivative curves

Quarter root plot: Straight line

Psuedo-Linear Flow

Follows bilinear flow after a transition period

Log-log plot: Half slope of the derivative curve

Square root time plot: straight line

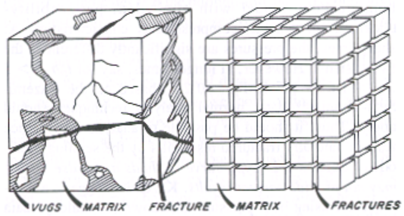
Formation Linear Flow

Linear flow from formation into fractures

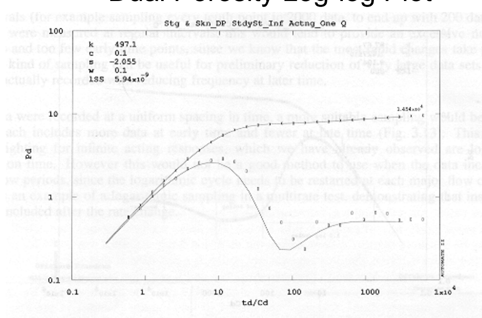
Log-log plot: Half slope on both the pressure and derivative plots

Square root time plot: Straight line

Naturally Fractured Rock

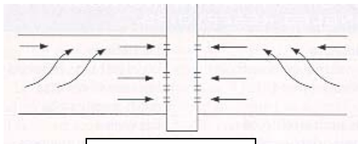


Dual Porosity Log-log Plot



- **Fracture system will be observed first on the falloff followed by the total system (fractures + tight matrix rock)**
- **Complex falloff analysis involved**
- **Falloff derivative trough indicates the level of communication between fractures and matrix rock**

Layered Reservoirs



Crossflow

Layered System with Crossflow

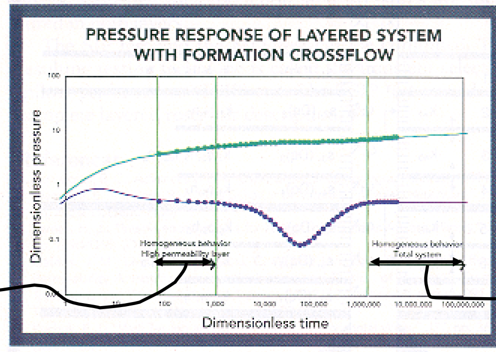


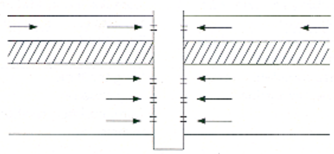
Fig. 6. In a layered reservoir, homogeneous behavior is exhibited during two different periods.

Homogeneous behavior of the higher permeability layer

Homogeneous behavior of the total system

Figures taken from Harts Petroleum Engr Intl, Feb 1998

Layered Reservoirs



Commingled

Layered system response

Homogeneous system response

Homogeneous behavior
Both layers infinite acting

High perm layer bounded
Low perm layers infinite acting

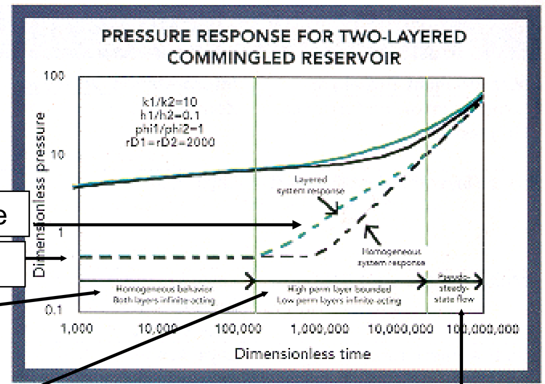


Fig. 7. Homogeneous behavior is exhibited during early times for a commingled reservoir.

Psuedo-steadystate flow

Figures taken from Harts Petroleum Engr Intl, Feb 1998

Layered Reservoirs

- Analysis of a layered reservoir is complex
  - Different boundaries in each layer
- Falloff objective for UIC purposes is to get a total transmissibility from the whole reservoir system

Pressure Derivative Flow Regime Patterns

Flow Regime	Derivative Pattern
Wellbore Storage …….	Unit slope
Radial Flow ……………	Flat plateau
Linear Flow ……………	Half slope
Bilinear Flow ………….	Quarter slope
Partial Penetration …..	Negative half slope
Layering ……………….	Derivative trough
Dual Porosity …………	Derivative trough
Boundaries ……………	Upswing followed by plateau
Constant Pressure …..	Sharp derivative plunge

Log-log Plot Summary

- **Logarithmic derivative combines the slope trend of the semilog plot with the log-log plot to magnify flow regime patterns**
- **The derivative trend determines what portion of the test can be used to evaluate the semilog straight line**
- **Various flow regimes show up on the derivative plot with specific patterns**

Falloff Test Evaluation Procedure

- **Data acquisition:**
  - **Well information**
  - **Reservoir and injectate fluid parameters**
  - **Reservoir thickness**
  - **Rate histories**
  - **Time sync injection rate data with pressure data**

Data acquisition:

Well information obtained from the well schematic

Well radius, r_w

Type of completion

Reservoir and injectate fluid parameters

Porosity, Φ (well log or core data)

Compressibility, c_t (correlations, core measurement, or well test)

Viscosity, μ_f and μ_w (direct measurement or correlations)

Estimate of reservoir thickness, h

Review flow profile surveys or slug chases from MIT

Well log and cross-sections

Rate histories

Test well prior to the test

Constant or variable

Offset wells prior to and during the test

Constant or variable

Time sync injection rate data with pressure data

Falloff Evaluation Procedure

- Prepare a Cartesian plot of pressure and temperature versus time
  - Confirm stabilization of pressure prior to shut-in
  - Look for anomalous data
  - Did pressure change reach the resolution of the gauge?

Prepare a Cartesian plot of pressure and temperature versus time

Confirm stabilization of pressure and temperature measurements prior to shut-in

Look for anomalous data

Missing data

Pressure rise or jump in data

Fluctuations in temperature can impact the pressure measurement

Determine if the pressure change reached the resolution of the gauge

If the test has not reached radial flow, a Cartesian plot can indicate if continuing the test can provide additional data given the resolution of the pressure gauge used for the test.

Falloff Evaluation Procedure

- Prepare a log-log plot of the pressure and the derivative
  - Use appropriate time scale
  - Identify the radial flow period
    - Flattening of the derivative curve
  - If there is no radial flow period, resort to type curve matching

Falloff Evaluation Procedure

- **Make a semilog plot**
  - **Use the appropriate time function**
    - **Horner or Superposition time**
  - **Draw a straight line of best fit through the points located within the equivalent time interval where radial flow is indicated by the derivative curve on the log-log plot**
  - **Determine the slope m and P_{1hr} from the semilog straight line**

Calculate reservoir and completion parameters

transmissibility, kh/μ

skin factor, s

radius of investigation, r_i, based on Agarwal equivalent time, t_e

Check results using type curves (optional)

Falloff Evaluation Procedure

- Calculate reservoir and completion parameters
  - transmissibility, kh/μ
  - skin factor, s
  - radius of investigation, r_i, based on Agarwal equivalent time, t_e
- Check results using type curves (optional)

Use a common sense check of the values calculated for s and kh/μ

Are these parameters what would be expected of the completed reservoir and well condition?

Skin will be used to correct injection pressure for skin effects.

The distance into the reservoir observed in the test is based on the r_i

Should any boundaries have been observed?

Gulf Coast Falloff Test Example

- **Well Parameters:**
  - r_w = .4 ft
  - cased hole perforated completion
    - 6020'- 6040'
    - 6055'- 6150'
    - 6196'- 6220'
  - Depth to fill: 6121'
  - Gauge depth: 6100'
    - Panex 2525 SRO

Based on this limited data, what potential issues might you already be looking for?

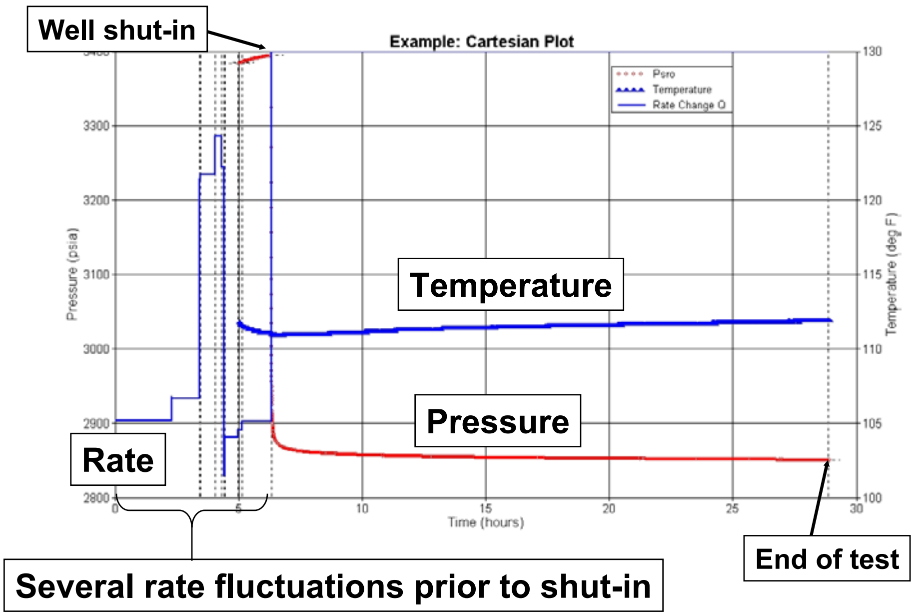
Layering based on the three sets of perforations

Partial penetration, since the lower set of perforations is completely covered by wellbore fill

Example (cont.)

- **Reservoir Parameters:**
  - **Reservoir thickness, h: 200'**
  - **Average porosity, ϕ: 28%**
  - **Total compressibility, c_t: 5.7e^{-6} psi^{-1}**
- **Formation Fluid Properties**
  - **Viscosity, μ_f: 0.6 cp**

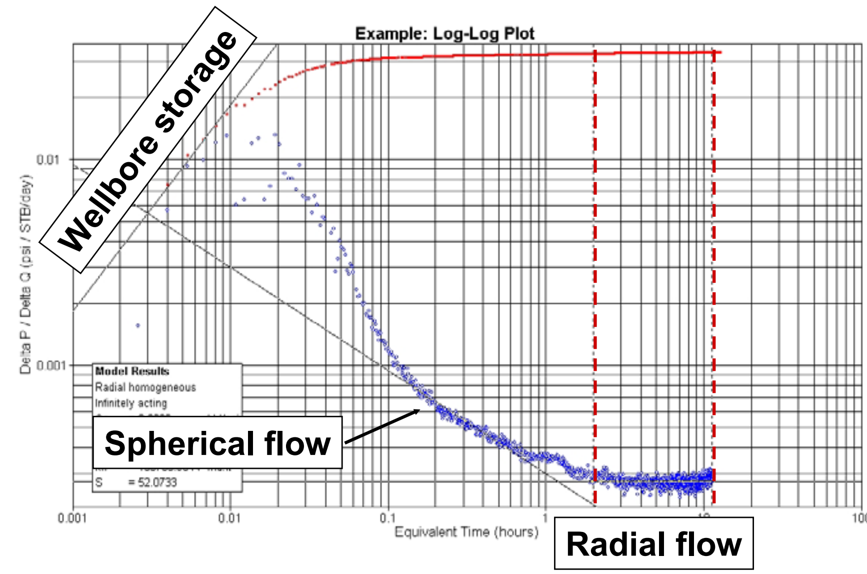
Example (cont.)



Notice the slight incline in the pressure just prior to shut-in. The pressure in this well had not stabilized prior to shut-in for the falloff test.

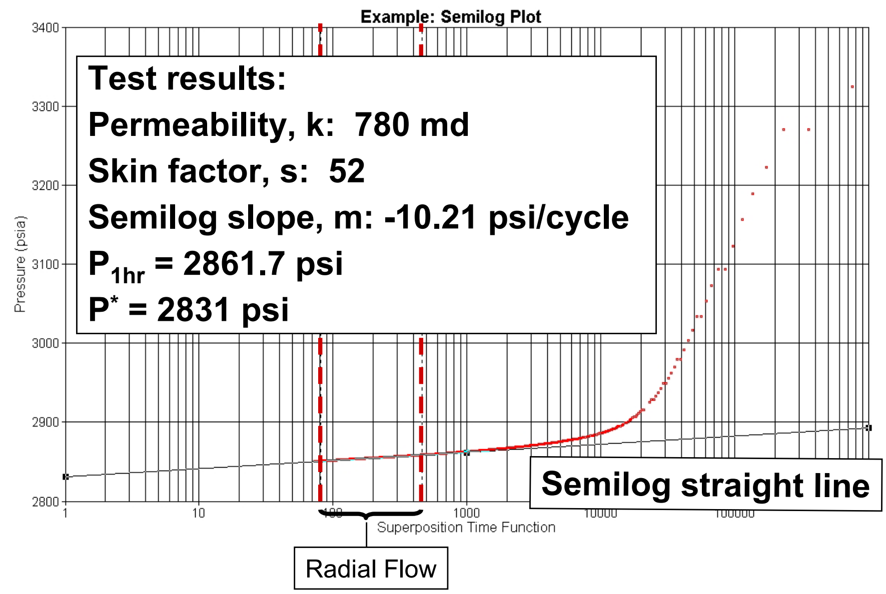
Several different rate changes occurred prior to shut-in so use a superposition time function to analyze this test. This requires the previous rate history that is available for this well.

Log-log Plot



Example: Log-Log Plot
Wellbore storage
Spherical flow
Radial flow
Model Results
Radial homogeneous
Infinitely acting
S = 52.0733
Delta P / Delta Q (psi / STB/day)
0.01
0.001
0.001
0.01
0.1
1
100
Equivalent Time (hours)

Semilog Plot



Positive skin factor as expected.

Type Curves

- Graphs of P_d vs. t_d for various solutions to the PDE
- Provide a “picture” of the PDE for a certain set of boundary conditions
- Work when the specialized plots do not readily identify flow regimes

Type curves:

Graph dimensionless variables, P_d vs. t_d for various solutions to the P-T PDE

Provide a “picture” of what a solution to the PDE looks like for a certain set of boundary conditions

Determined from either analytical or numerical solutions

Cover a wide range of parameter combinations and work even when specialized plots do not readily identify flow regimes

Applied to field data analysis by a process called “type curve matching”

Generally based on drawdowns/injectivity tests

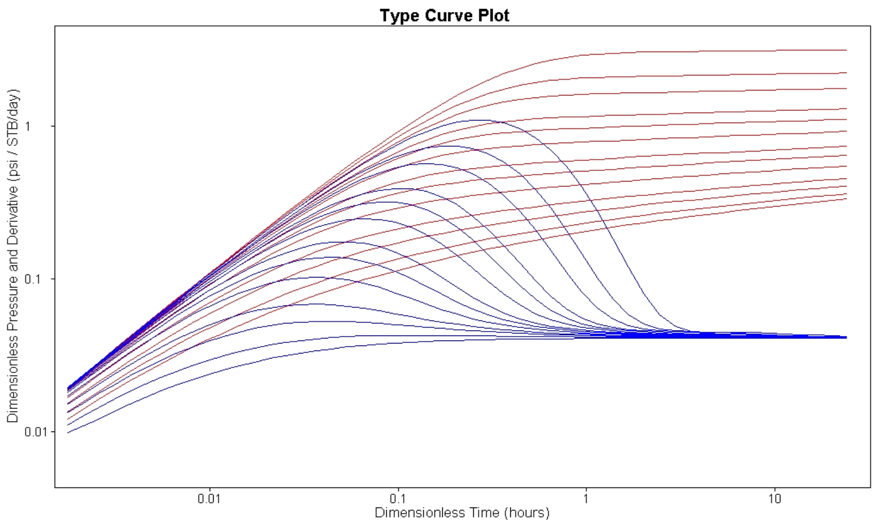
May require plotting test data with specialized time functions to use correctly

May provide a welltest analysis when specialized plots do not identify a radial flow regime

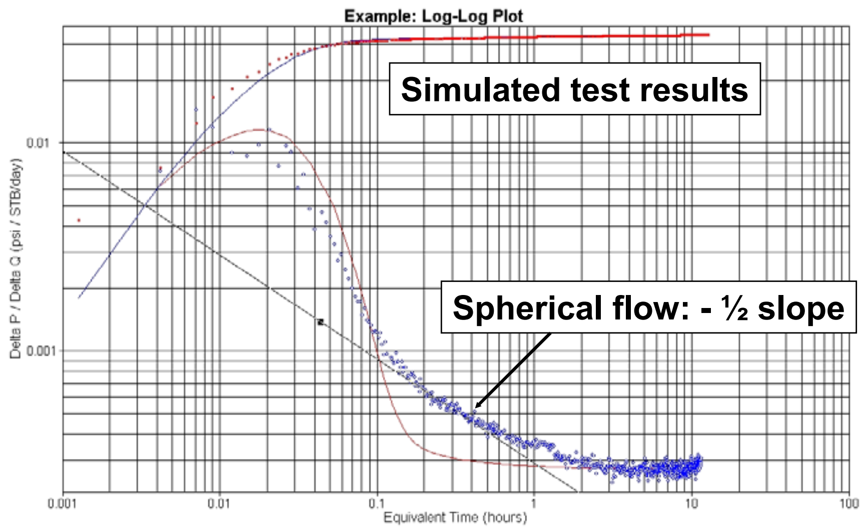
Type Curves

- Applied to field data analysis by a process called "type curve matching"
- Generally based on drawdowns/injectivity
- May require plotting test data with specialized time functions to use correctly

Example: Homogeneous Reservoir Type Curves



Type Curve Match



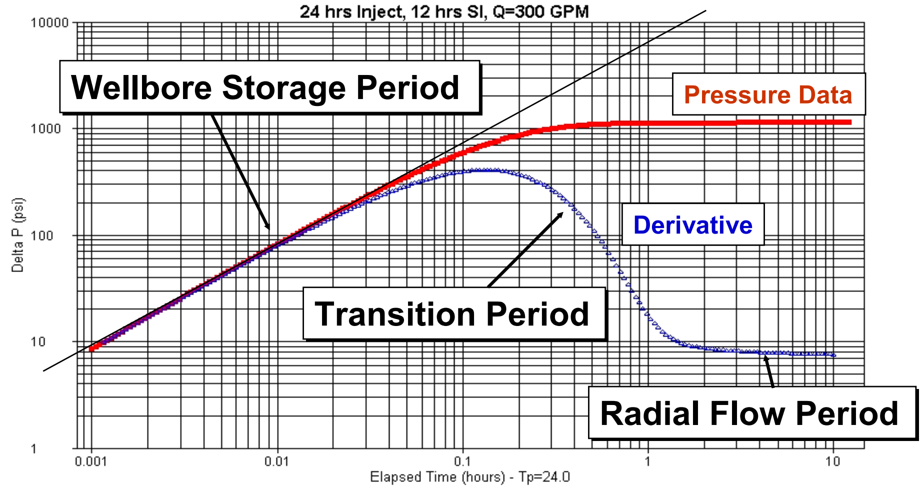
Here is a type curve match to our previous example

Effects of Key Falloff Variables

Key Falloff Variables

- Length of injection time
- Injection rate
- Length of shut-in (falloff) period
- Wellbore skin
- Wellbore storage coefficient

Log-Log Plot


24 hrs Inject, 12 hrs SI, Q=300 GPM
Wellbore Storage Period
Pressure Data
Derivative
Transition Period
Radial Flow Period
Delta P (psi)
10000
1000
100
10
1
0.001
0.01
0.1
1
10
Elapsed Time (hours) - Tp=24.0

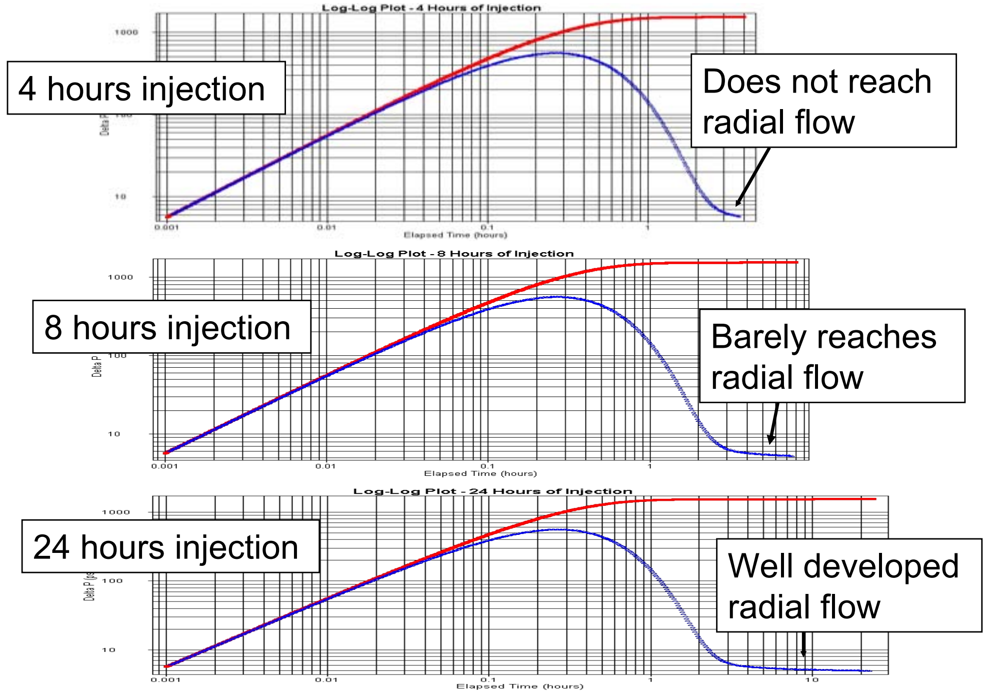
Effect of Injection Time

- Length of injection period controls the radius of investigation of the falloff test
- Falloff is a “replay” of the preceding injection period
- Falloff period cannot see any further out into the reservoir than the injection period did
- Injection period should be long enough to establish radial flow

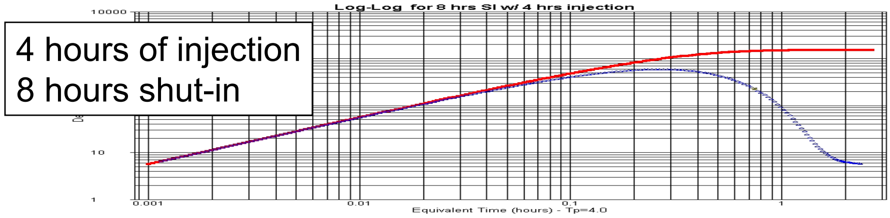
Injection Time

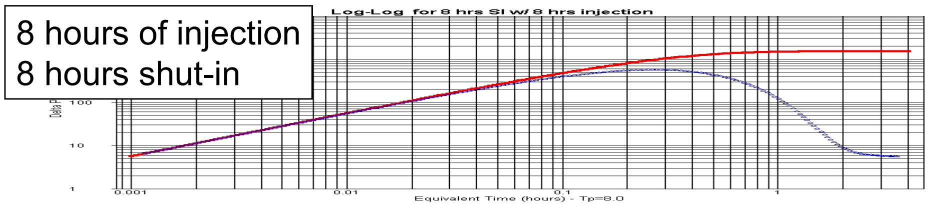
- **Increase injection time to observe presence of faults or boundary effects**
- **Calculate minimum time needed to reach a certain distance away from the injection well**

Simulated Injection Periods - Same Properties, Varying Duration



Log-log Plots for Injection Periods of Varying Length





Summary of Injection Time Effects

- When injection time is shorter than the falloff, it compresses the falloff response on log-log plot
- Longer injection time extends the falloff response
- When injection time is very long relative to the falloff time, it has little effect on the falloff response

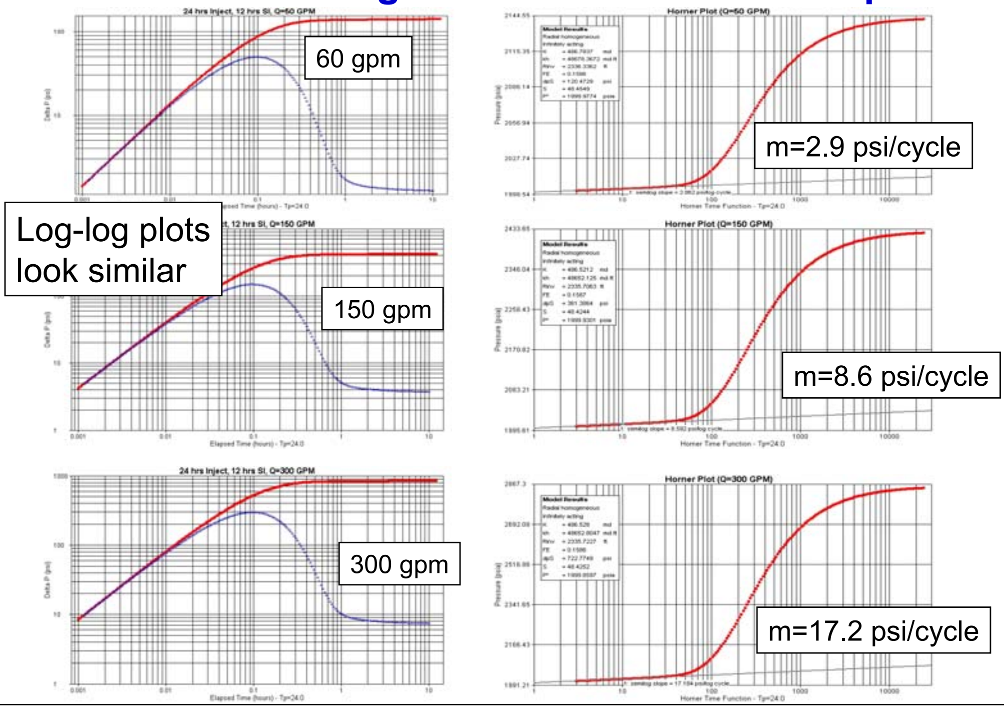
Effects of Injection Rate

- Rate determines the magnitude of pressure rise during the injection period and the amount of pressure falloff during shut-in period
- Too small a rate can minimize the degree of pressure change measured during a falloff test
- Rate limit during a test may be constrained by permit limits, formation transmissibility, skin factor, or waste storage capacity

Injection Rate Effects

- Injection rate preceding the test may be limited by the UIC permit and no migration petition requirements or operational considerations including:
  - available injectate capacity
  - pumping capacity
  - surface pressure or rate limitations

Effect of Increasing Rate on Falloff Test Response



Summary of Injection Rate Effects

- Higher rate increases the amount of pressure buildup during injection resulting in:
  - Greater total falloff pressure change
  - Larger slope of the semilog plot during radial flow
  - Increased semilog slope enables a more reliable measurement of radial flow

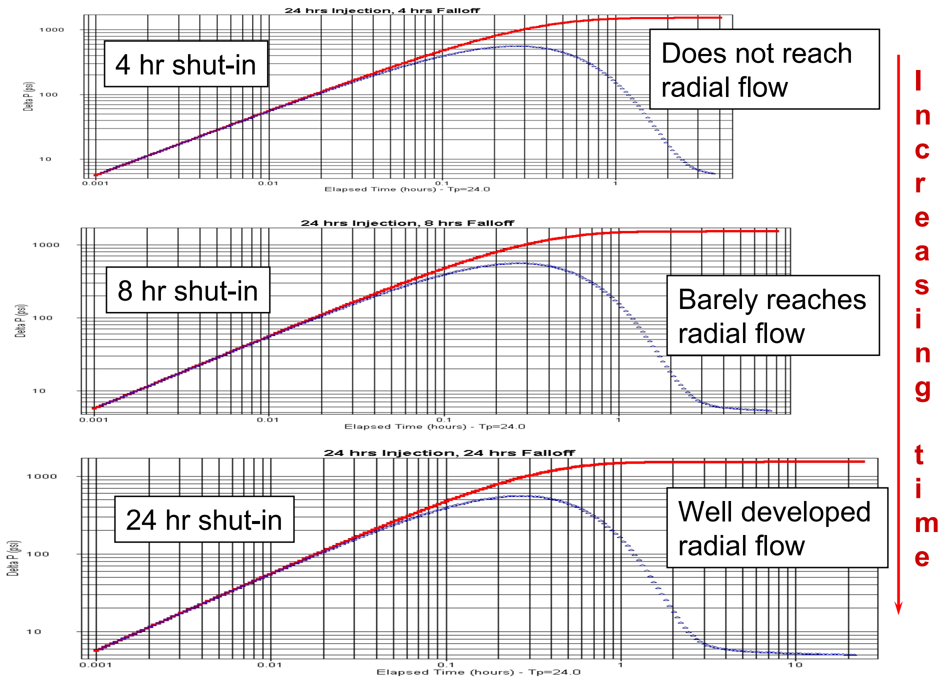
Effect of Shut-in Time

- Too little shut-in time prevents the falloff from reaching radial flow, making it unanalyzable
- Shut-in time exceeding the injection period length is compressed when plotted with the proper time function on the log-log plot

Shut-in Time

- **Falloff data should be plotted with an appropriate time function on a log-log plot to account for the effects of the injection period on the shut-in time**
- **Increase falloff time to observe presence of faults and boundary effects if preceding injection period was long enough to encounter them**

Comparison of Shut-in Times for Identical Injection Conditions



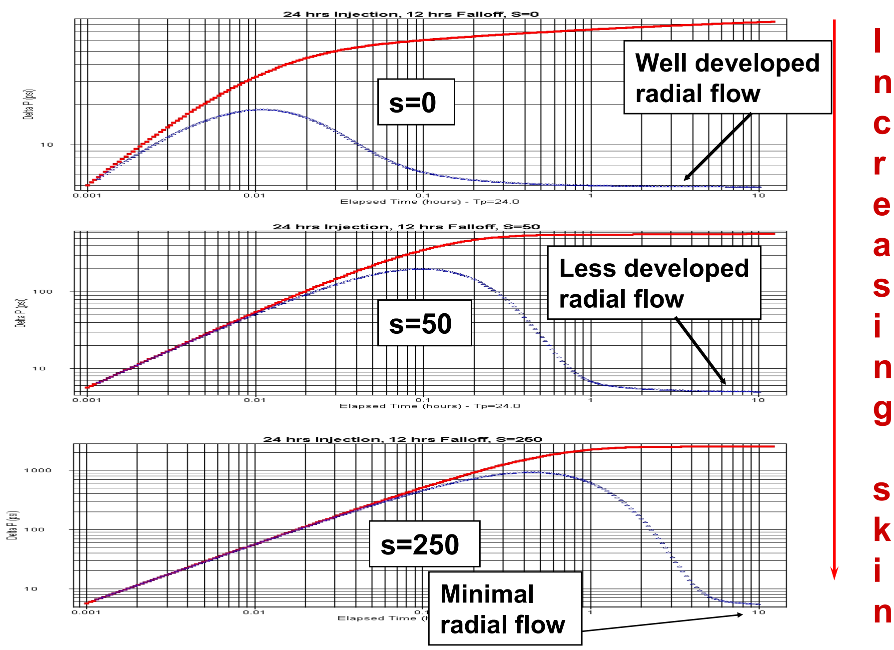
Summary of Shut-in Time Effects

- Too short a shut-in time results in no radial flow
- Shut-in time may be dictated by the preceding injection time
  - Falloff is a replay of the injection
- Wellbore storage, skin, and need to observe a boundary may increase the required shut-in time

Effects of Wellbore Storage and Skin Factor

- A positive skin factor increases the time to reach radial flow
- A negative skin reduces the time to reach radial flow
- Large wellbore storage coefficient increases time to reach radial flow
  – Caused by well going on a vacuum, formation vugs, presence of fracture or large wellbore tubular dimensions

Comparison of Skin Effect for Identical Falloff Conditions



Boundary Effects

What Can I Learn About Boundaries from a Falloff Test?

- **Derivative response indicates the type and number of boundaries**
- **If radial flow develops before the boundary effects, then the distance to the boundary can be calculated**

Derivative response shape indicates the type and number of boundaries

1 fault causes the semilog slope to double

2 perpendicular faults cause the slope to quadruple if fully developed

Derivative response shape can provide the position of the well relative to the boundaries. If radial flow develops before the boundary effects, then the distance to the boundary can be calculated

How Long Does It Take To See A Boundary?

- **Time to reach a boundary can be calculated from the radius of investigation equation:**

$$t_{boundary} = \frac{948 \cdot \phi \cdot \mu \cdot c_t \cdot L_{boundary}}{k}$$

  - **Where $L_{boundary}$ is the distance in feet to the boundary**
  - **$t_{boundary}$ is in hours**

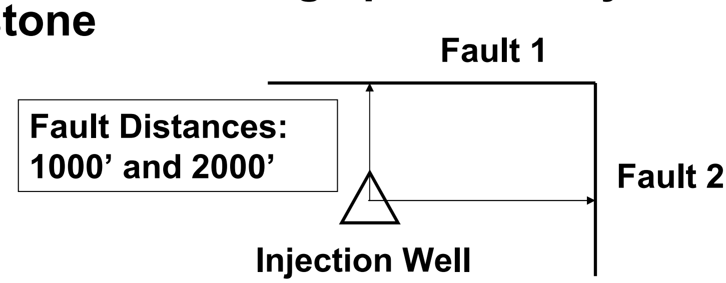
How Long Does It Take To See A Boundary?

- **For a boundary to show up on a falloff, it must first be encountered during the injection period**
- **Additional falloff time is required to observe a fully developed boundary on the test past the time needed to just reach the boundary**

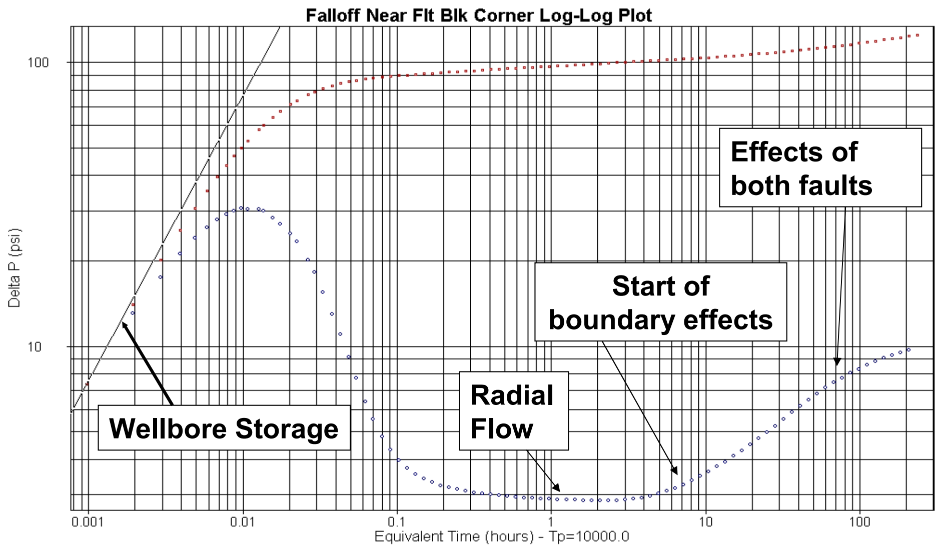
Rule of thumb: Allow at least 5 times the length of time it took to see the boundary to see it fully developed on a log-log plot

Example: Well Located Near 2 Faults

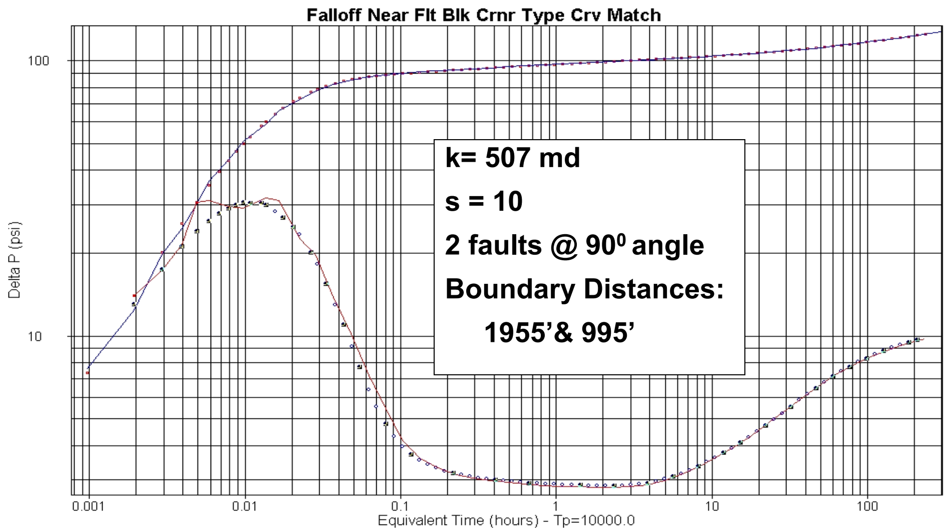
- An injection well injects at 2000 bpd for 10,000 hours and then is shut-in for 240 hours
- The well is located in the corner of a fault block
- The reservoir is a high permeability sandstone



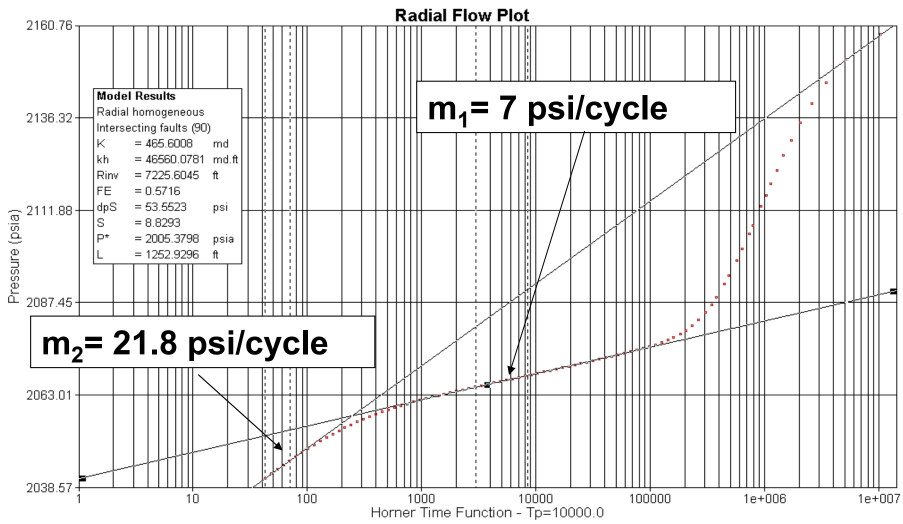
What Does the Falloff Look Like with Boundary Effects?



Type Curve Analysis of Falloff with Boundary Effects



Falloff with Boundary Effects Semilog Plot



m_2 indicates more than 1 boundary

Summary of Boundary Effects on a Falloff Test

- Use the log-log plot as “master test picture” to see response patterns
- Look for slope changes in pressure and pressure derivative trends
- Inner boundary conditions such as wellbore storage, partial penetration, and hydraulic fractures typically observed first
- Outer boundary effects show up after radial flow occurs if you’re lucky!

Use the log-log plot as “master test picture” to see response patterns

Look for slope changes in pressure and pressure derivative trends to identify boundary effects

Inner boundary conditions such as wellbore storage, partial penetration, and hydraulic fractures are typically observed first

Outer boundary effects are usually observed after radial flow occurs (flat derivative trend)

Typical Outer Boundary Patterns

- **Infinite acting**
  - No outer boundary
  - Only radial flow is observed on log-log plot
- **Composite reservoir**
  - Derivative can swing up or down and re-plateau
- **Constant pressure boundary**
  - Derivative plunges sharply

Infinite acting – no outer boundary observed and only radial flow is observed on log-log plot

Composite reservoir (change in transmissibility (kh/u) or a mobility change (change in permeability/viscosity ratio, k/u)) - derivative can swing up or down and re-plateau

Constant pressure boundary– derivative plunges sharply

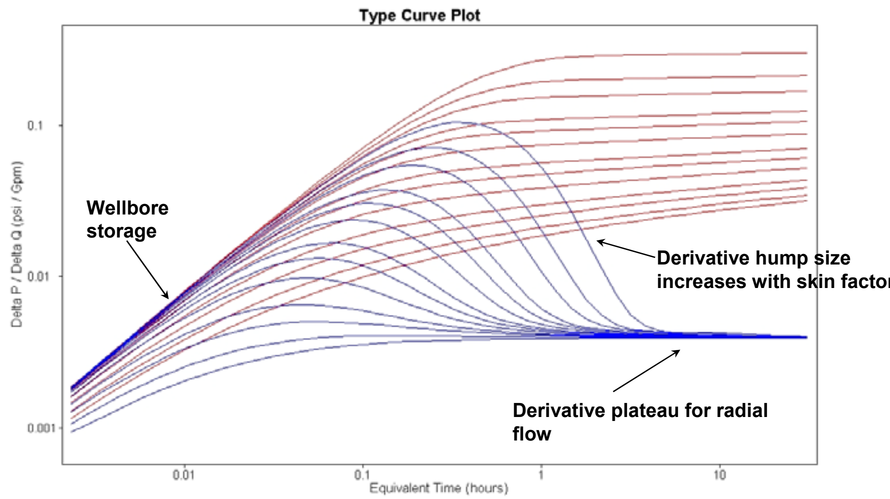
No flow boundary – derivative upswing followed by a plateau – multiple boundaries cause variations in shape and degree of the upswing

Pseudosteady state – all boundaries around the well reached – derivative swings up to a unit slope – injector is in a closed shape

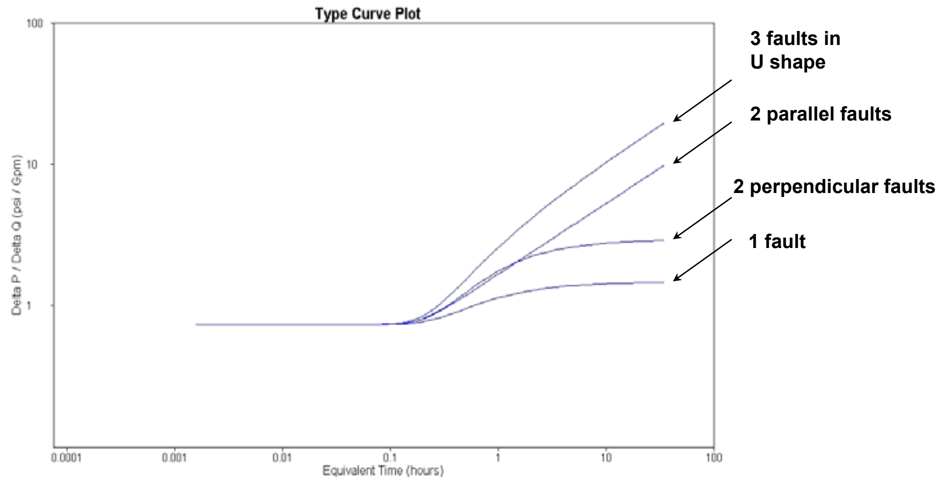
Typical Outer Boundary Patterns

- No flow boundaries
  - Derivative upswing followed by a plateau
  - Multiple boundaries additional degrees of the upswing
- Pseudo-steady state
  - all boundaries reached
  - closed reservoir
  - derivative swings up to a unit slope

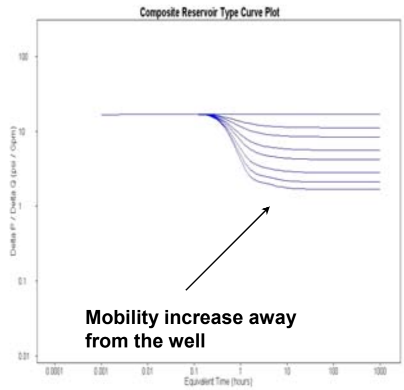
Infinite Acting Reservoir – No Boundary

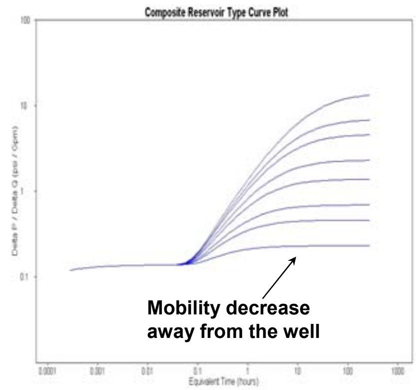


Boundary Effects from Sealing Faults – Derivative Patterns



Boundary Effects from a Composite Reservoir – Derivative Patterns





Is It a Real Boundary?

- **Check area geology**
- **Type of injectate**
- **Both the injection and falloff have to last long enough to encounter it**
- **Most pressure transient tests are too short to see boundaries**

Check area geology for boundaries and possible permeability and net thickness changes to justify the test response

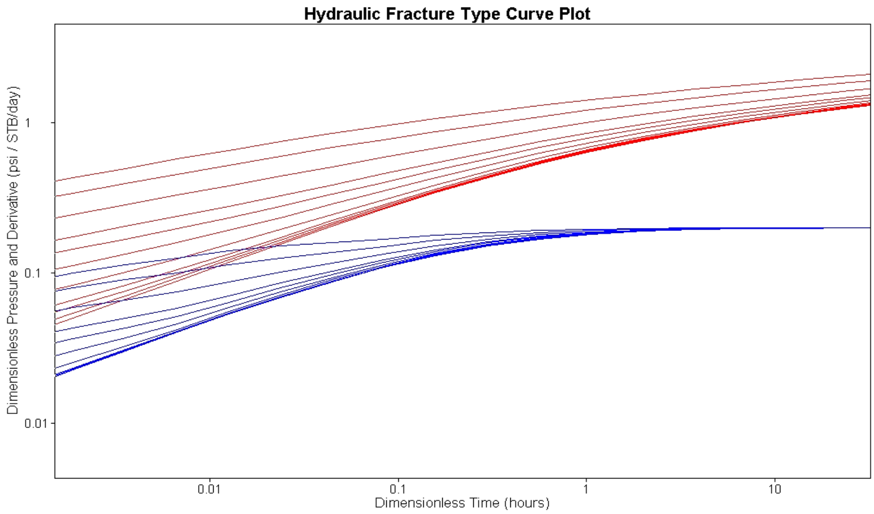
> A composite reservoir can give a similar signature to a conventional boundary

The type of injectate may also impact the test – waste acids, viscous wastes

To observe a boundary in the welltest, both the injection and falloff have to last long enough to encounter it

Most pressure transient tests are too short to see boundaries

Example: Hydraulic Fracture Type Curves

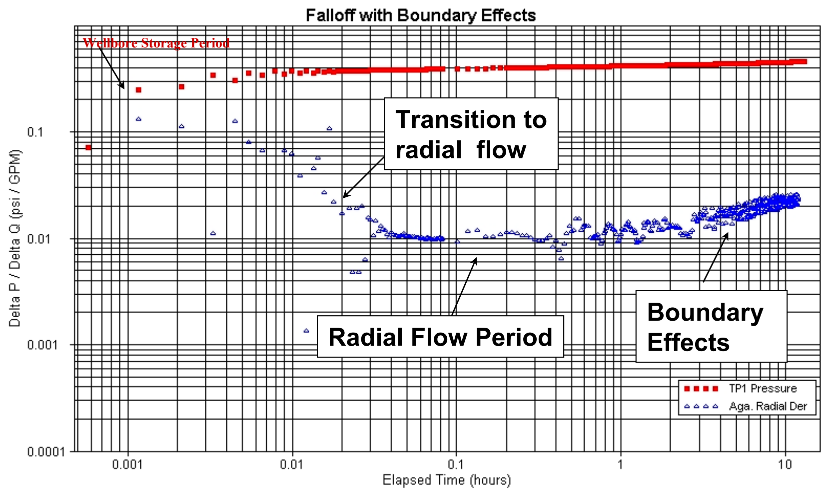


Log-log Plot Examples

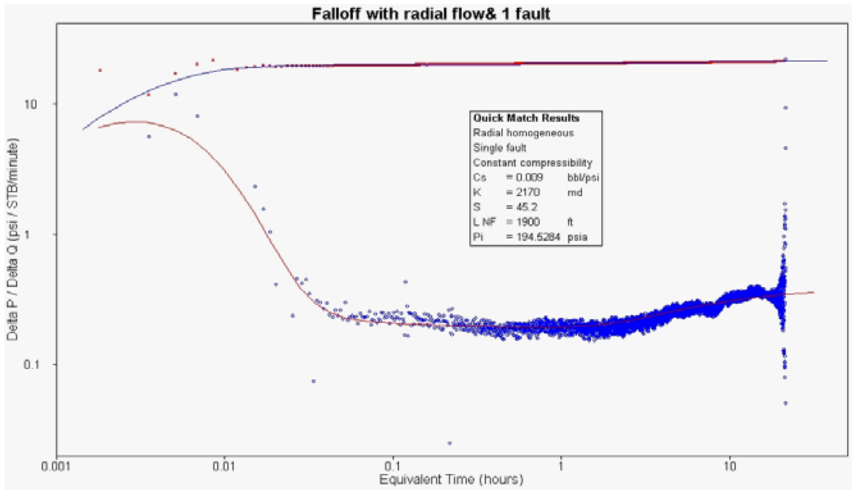
A Gallery of Falloff Log-log Plots

- Radial flow with boundary effects
- Falloff with a single fault
- Falloff in a hydraulically fractured well
- Falloff in a composite reservoir
- Falloff with skin damage
- Falloff after stimulation
- Falloff with spherical flow
- Simulated pseudosteady state effects

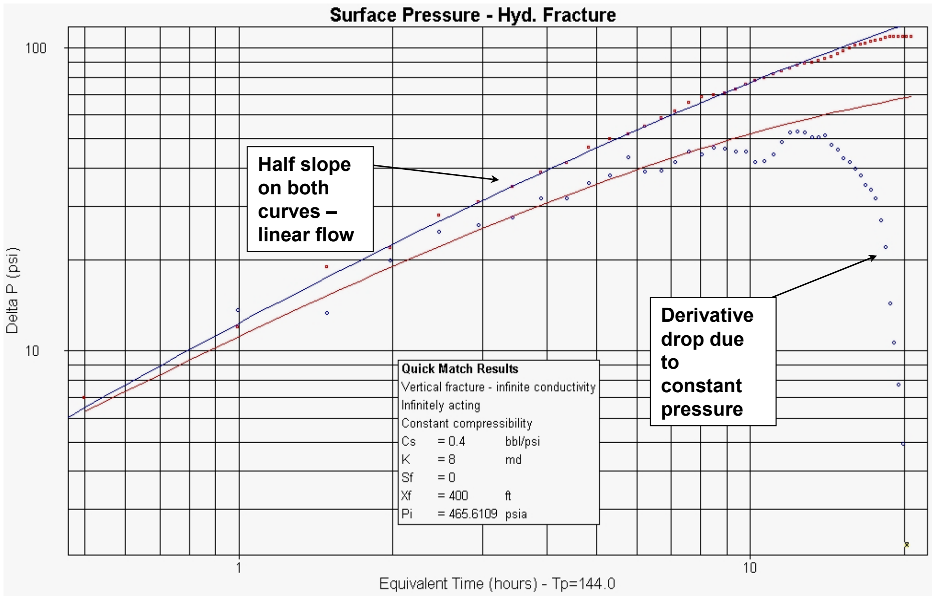
Radial Flow Followed by Boundary Effects



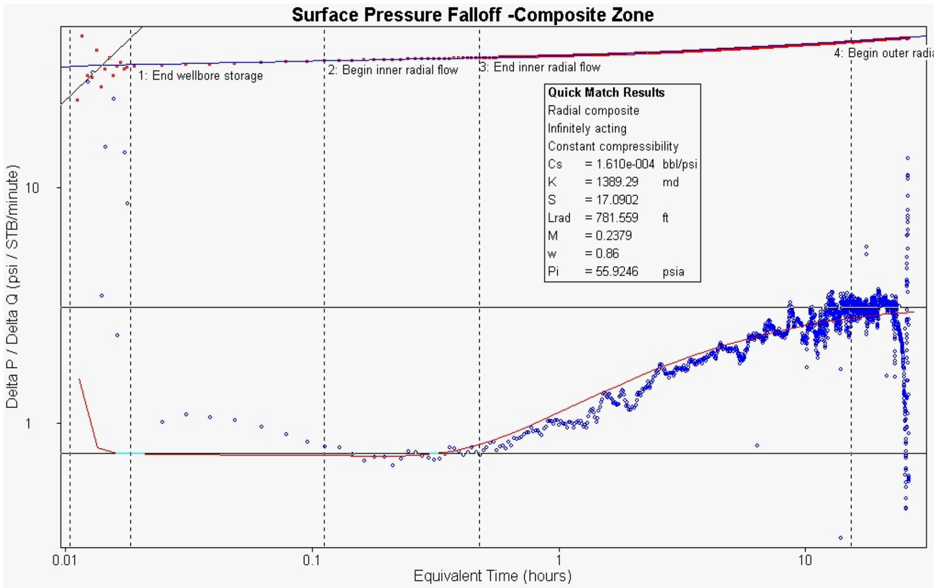
Falloff with a Single Fault



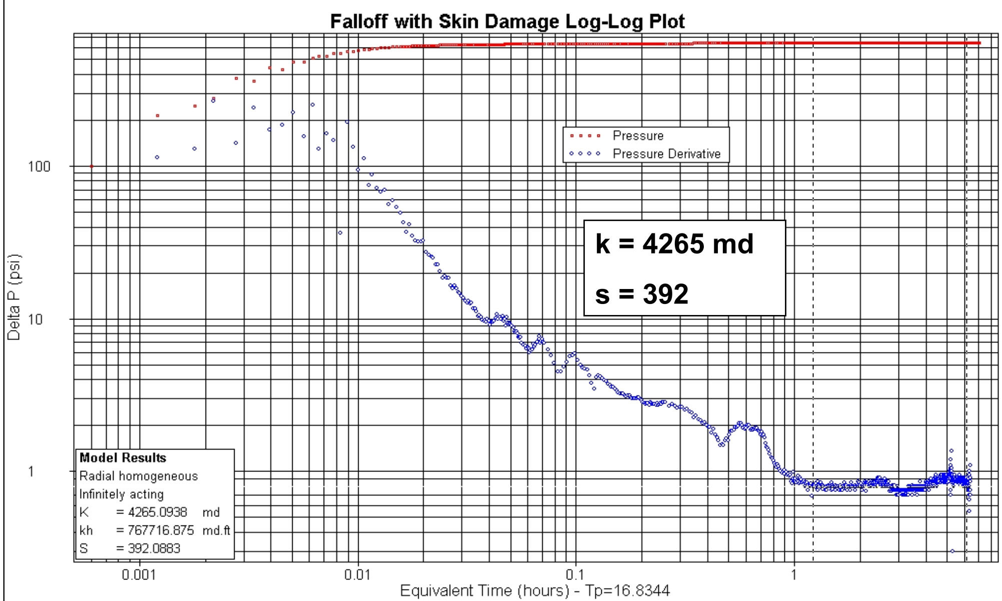
Falloff with a Hydraulic Fracture



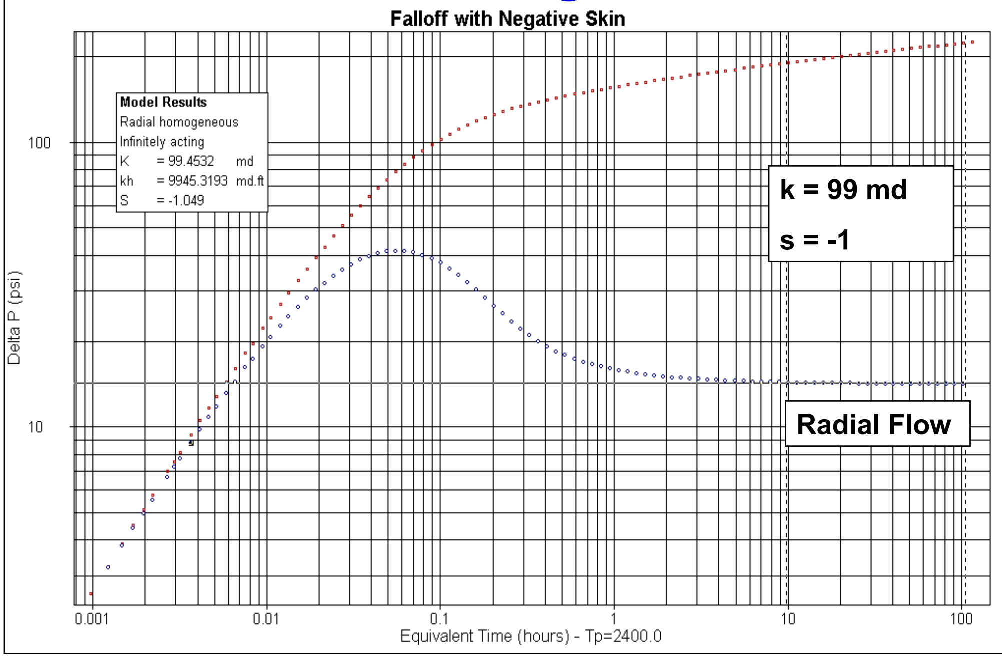
Falloff in a Composite Reservoir



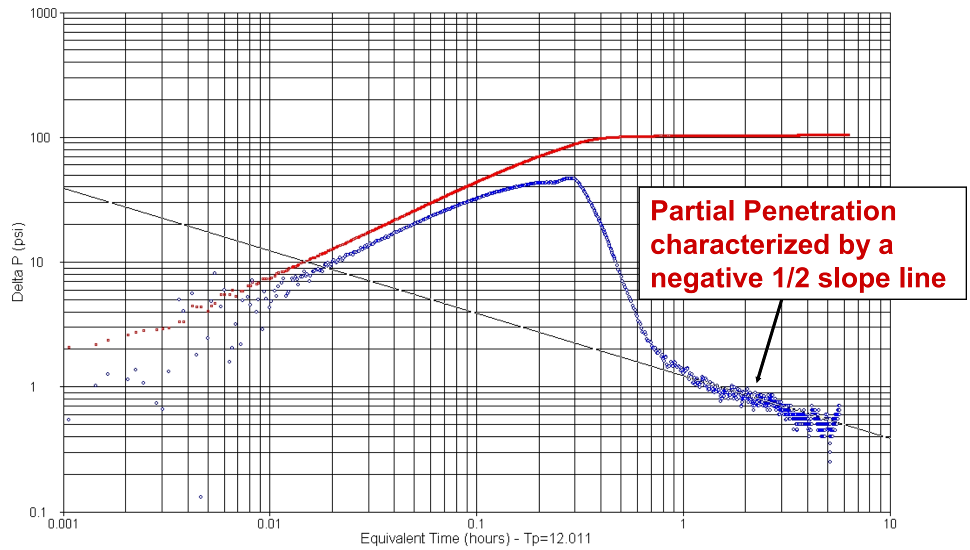
Falloff with Skin Damage



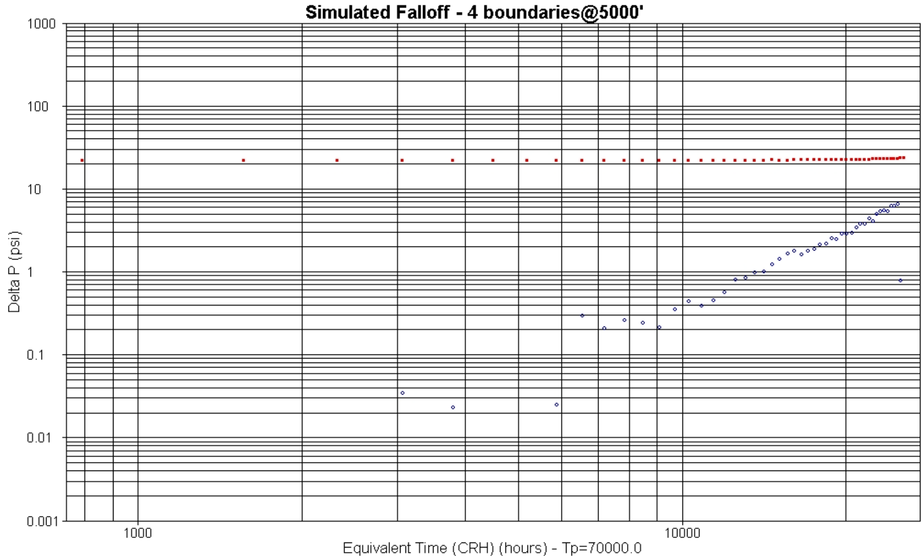
Falloff with Negative Skin



Falloff Dominated by Spherical Flow



Simulated Falloff with Pseudo-steady State Effects



Other Types of Pressure Transient Tests

Other Types of Pressure Transient Tests

- Injectivity Test
  - Record pressure, time, and rate data from the start of an injection period following a stabilization period
  - Pros
    - Don’t have to shut in well
    - Generally maintain surface pressure so less wellbore storage
    - Less impact from skin

Other Types of Tests

- Cons
  - Noisy data due to fluid velocity by pressure gauge
  - Rate may fluctuate so an accurate history is important

Other Types of Tests

- **Multi-rate Injection Test**
  - **Record pressure, time, and rate data through at least two injection periods**
  - **Pros**
    - **Can be run with either a decrease or an increase in injection rate**
    - **Minimizes wellbore storage especially with a rate increase**
    - **Provides two sets of time, pressure, and rate data for analysis**
    - **Decreasing the rate provides a partial falloff without shutting in the well**

Other Types of Tests

- Cons
  - Noisy data due to fluid velocity by gauge
  - 1st rate period needs to reach radial flow

Other Types of Tests

- **Interference Test**
  - Use two wells: signal and observer
  - Signal well undergoes a rate change which causes pressure change at the observer
  - Measure the pressure change over time at the observer well and analyze with an Ei type curve or, if radial flow is reached, a semilog plot

Other Types of Tests

- Pros
  - Yields transmissibility and porosity-compressibility product between wells
  - May give analyzable results when falloff doesn't work
- Cons
  - Generally involves a small pressure change of 5 psi or less so accurate surface or bottomhole gauges are needed
  - Observable pressure change decreases as the distance between the two wells increases

Other Types of Tests

- Cons (cont.)
  - Complex analysis if more than two injectors are active
  - Need knowledge of pressure trend at the observer well
  - Test rate should be constant at the signal well

Other Types of Tests

- **Pulse Test**
  - Similar to interference except rate changes at observer well are repeated several times
  - Pros
    - Multiple data sets to analyze
    - Verify communication between wells more than one time
  - Cons
    - Difficult to analyze without welltest software – Monograph 5 methodology
    - Requires more time and planning and careful control of the signal well rate

Designing an Interference Test

- For both interference and pulse tests, the best design approach is to use a well test simulator
- Interference tests can designed using the Ei type curve
- Design information needed:
  - Distance between signal and observer wells
  - Desired pressure change to measure
  - Desired injection rate
  - Estimates of c_t, ϕ, μ, k, h, r_w

Interference Test Design Example

- Two injection wells are located 500' apart. Both wells have been shut in over 1 month
- An interference test is planned with an injection rate of 3000 bpd (87.5 gpm)
- k = 50 md, h = 100', ϕ = 20%, μ_f = 1 cp, c_t = 6×10^{-6} psi^{-1}, r_w = 0.3 ft
- How long will the test need to run to see a 3 psi change at the observer?

Interference Design Example

Ei Type Curve: from Figure C.2 in SPE Monograph 5

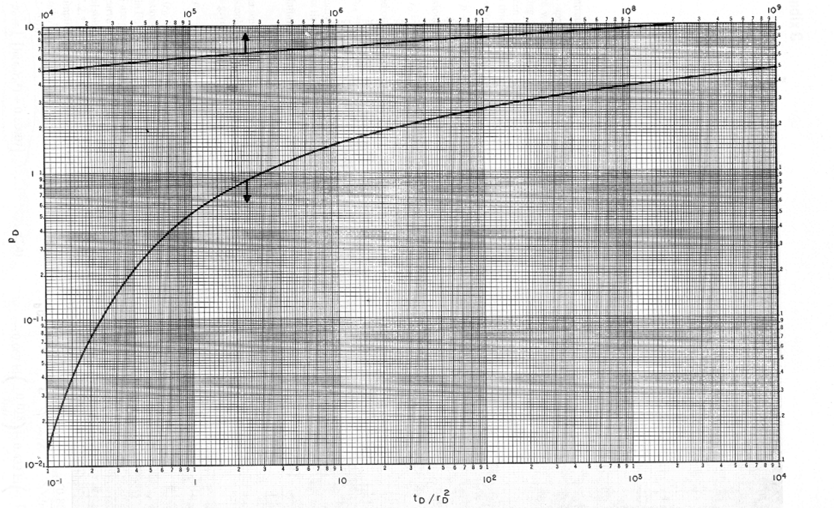


Fig. C.2 Dimensionless pressure for a single well in an infinite system, no wellbore storage, no skin. Exponential-integral solution.

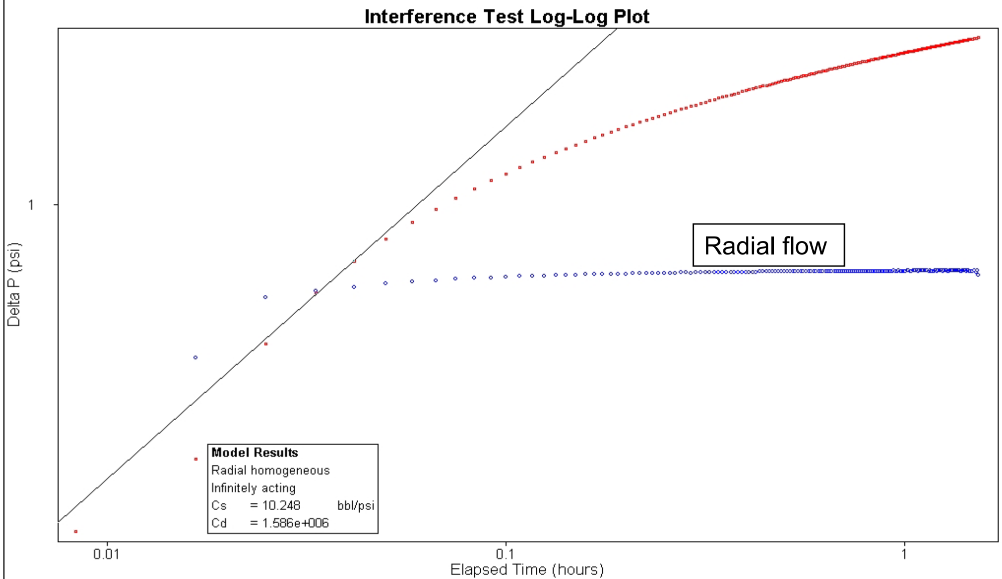
Interference Design Example

- Calculate P_D and r_D from equations listed in PDE discussion
- Find t_D/r_D^2 from corresponding P_D value on Ei type curve
- Calculate t_D and solve for $t_{interference}$
- Results:
  - P_D= 0.0354, r_D= 1666.7
  - t_D/r_D^2 = 0.15
  - t_D= 416,666.7
  - $t_{interference}$= 3.4 hours

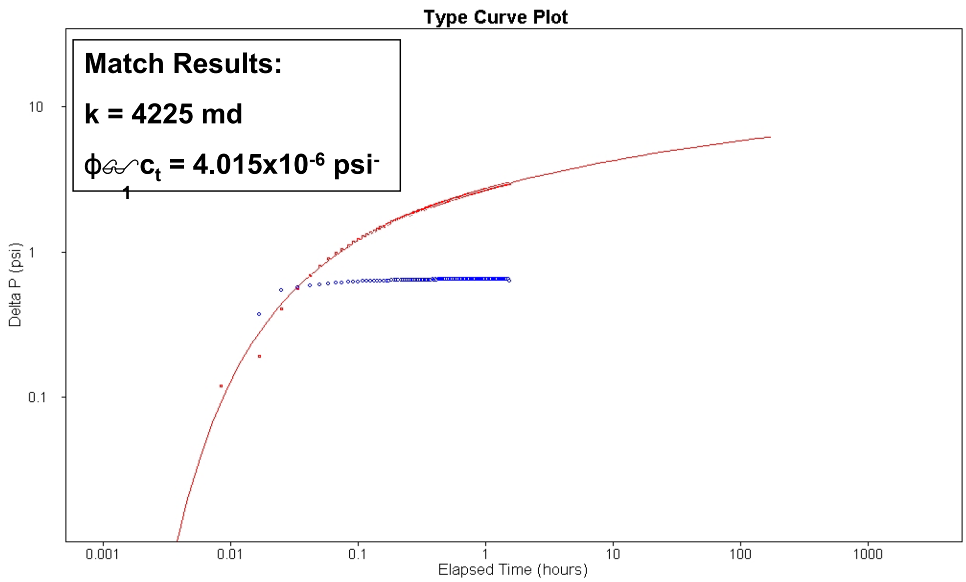
Interference Test Example

- An interference test is conducted between two injection wells at a Gulf Coast area facility.
- Reservoir conditions:
  - h=55', ϕ=28%, $c_t=6 \times 10^{-6}$ psi^{-1}, r_w=0.25 ft
- Well Data:
  - q = 120 gpm
  - wells are 150' apart

Interference Test Example: Log-log Plot at Observer Well



"Real World" Interference Type Curve Match



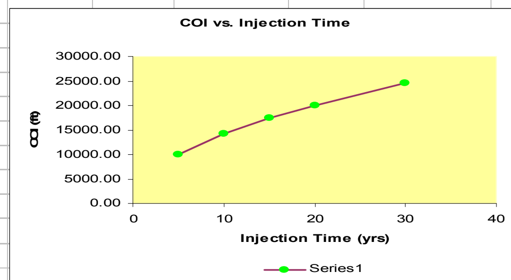
How Do Falloff Results Impact Area of Review

- **The transmissibility obtained from the falloff and the solution from the PDE can be used to project the pressure increase due to injection**
- **The PDE solution can also be used to estimate the location of the cone of influence**
- **Both the pressure projection and cone of influence location estimate can be set up in a spreadsheet**

Example Cone of Influence Estimate

Input Parameters	
Facility:	Example
Pi (initial resv. pressure in psia):	1200
h (ft):	50
porosity:	0.2
rw (ft):	0.3
ct (1/psi):	8.00E-06
viscosity (cp):	1.00
Depth to USDW base (ft):	300
Depth to Groundwater (ft):	10
Reservoir fluid SG:	1.040
Min. aband. well diameter (in.)	9.000
Min. aband. well mud wt. (lb/gal):	8.90
Top of injection interval (ft):	3000

Critical Pressure Calculations	
Critical pressure rise- brine filled borehole (psi):	141.43
Critical pressure rise - mud filled borehole (psi):	362.34
Critical pressure rise basis (enter mud or brine):	brine



COI Calculations Inj. Rate (bpd)	Inj. Rate (gpm)	Falloff k (md)	Injection Time (hrs)	Injection Time (yrs)	Dimensionless Time	Critical Pressure (psi)	Dimensionless Pressure	Dimensionless Radius	Total Pressure Increase at Injection Well (psi)	COI Radius (ft)
1714.29	50	20	43800	5	1.6042E+09	141.43	0.58	33462.23	2663.23	10038.67
1714.29	50	20	87600	10	3.2084E+09	141.43	0.58	47322.74	2747.12	14196.82
1714.29	50	20	131400	15	4.8125E+09	141.43	0.58	57958.29	2796.19	17387.49
1714.29	50	20	175200	20	6.4167E+09	141.43	0.58	66924.46	2831.01	20077.34
1714.29	50	20	262800	30	9.6251E+09	141.43	0.58	81965.39	2880.08	24589.62

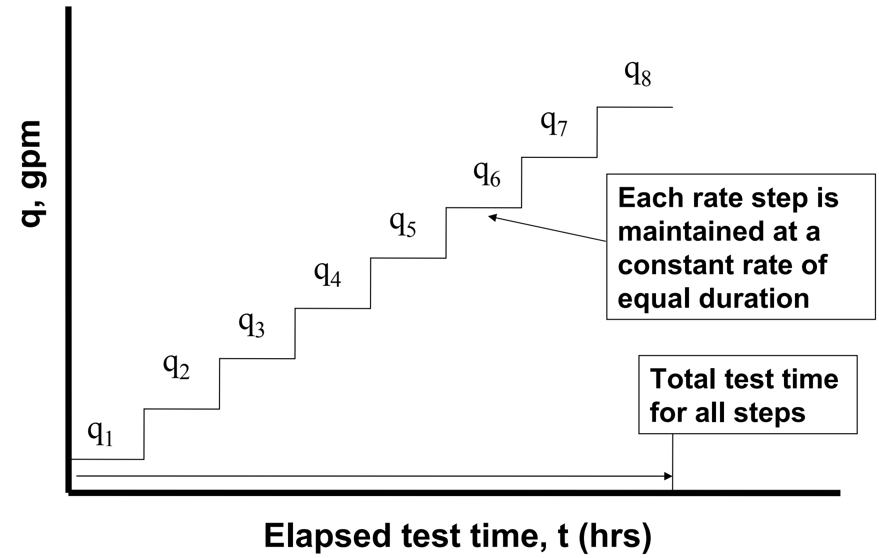
How is Fracture Pressure Determined?

- Typically estimated from fracture gradient correlations (e.g. Hubbert and Willis, Eaton)
- Can be determined from a step-rate test
- Fracture pressure varies with depth, lithology, and geographical region

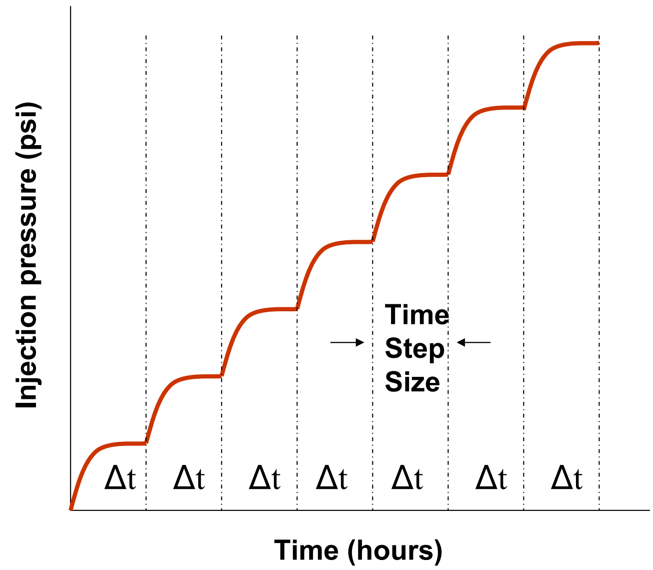
What is a Step-Rate Test?

- **Series of constant rate injection steps of equal time duration**
- **Each step can be analyzed as a pressure transient test (injectivity test)**

Step-Rate Test Rate Sequencing



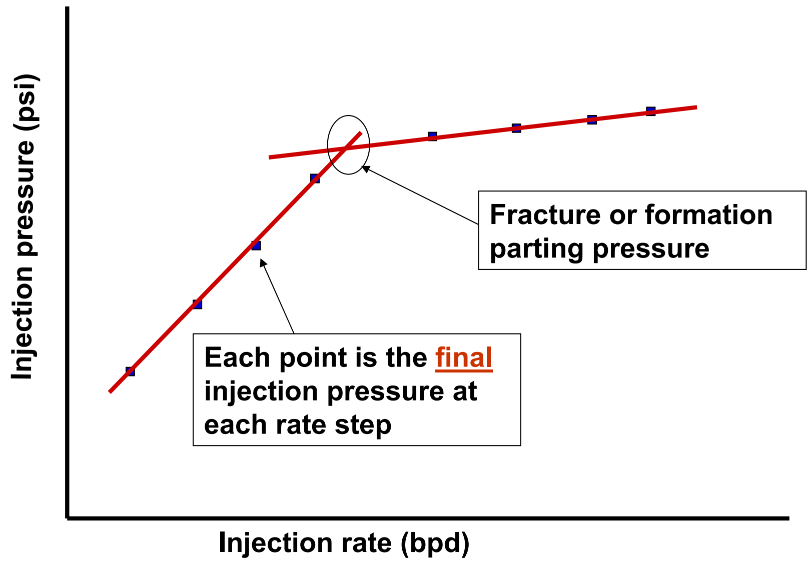
Step-Rate Test Pressure Behavior



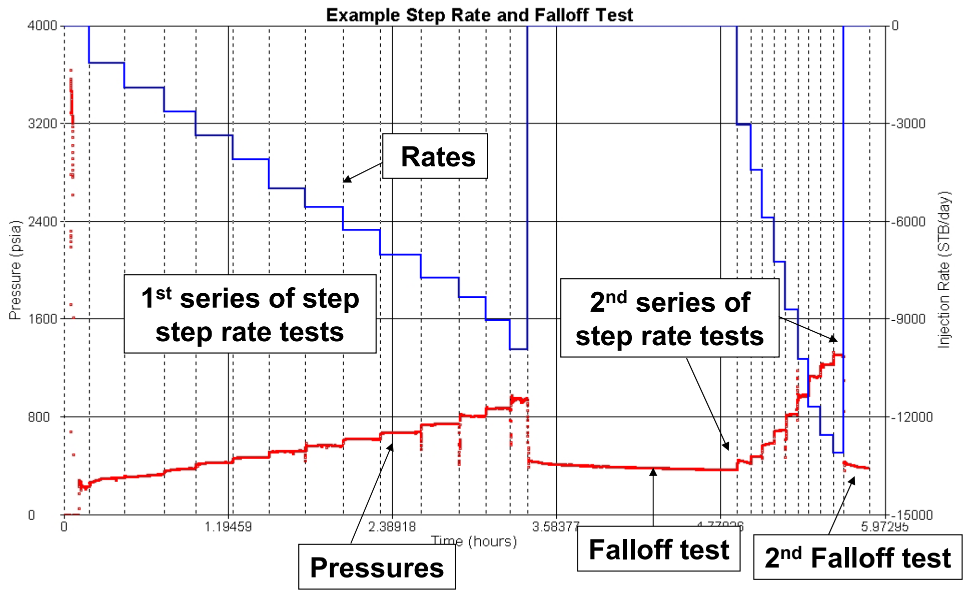
Step Rate Tests Analysis

- Data is analyzed using log-log and linear plots
- Use the linear plot to estimate fracture pressure (also called the formation parting pressure)
- Use the log-log plot to verify that fracturing occurs and estimate kh/u and skin

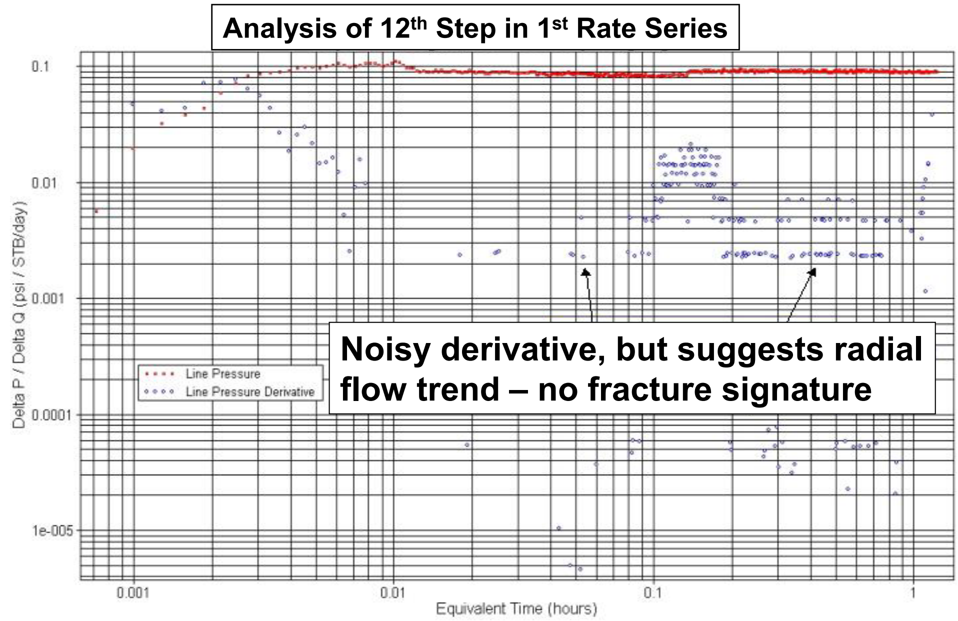
Step Rate Test Analysis: Linear Plot



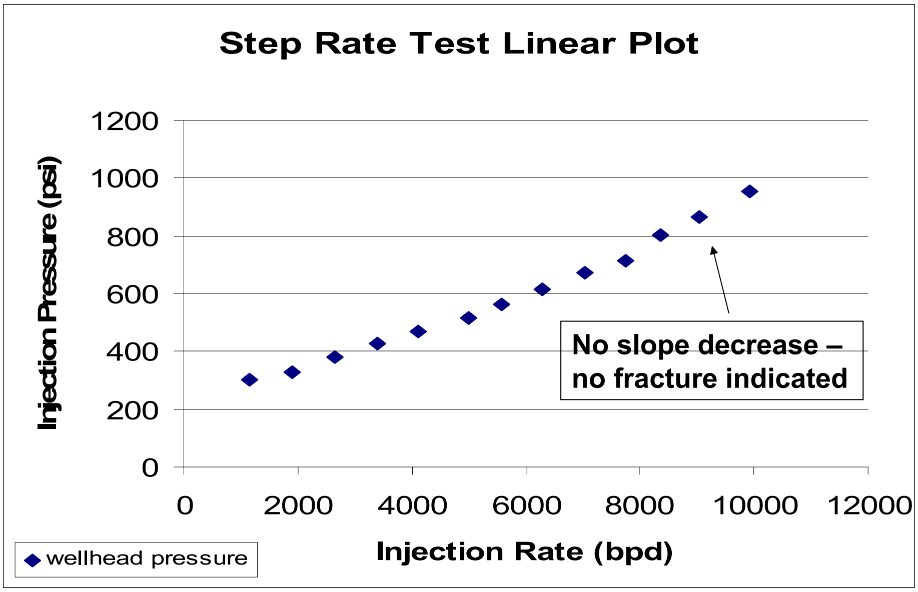
Example Step Rate Test



Log-Log Plot of a Rate Step



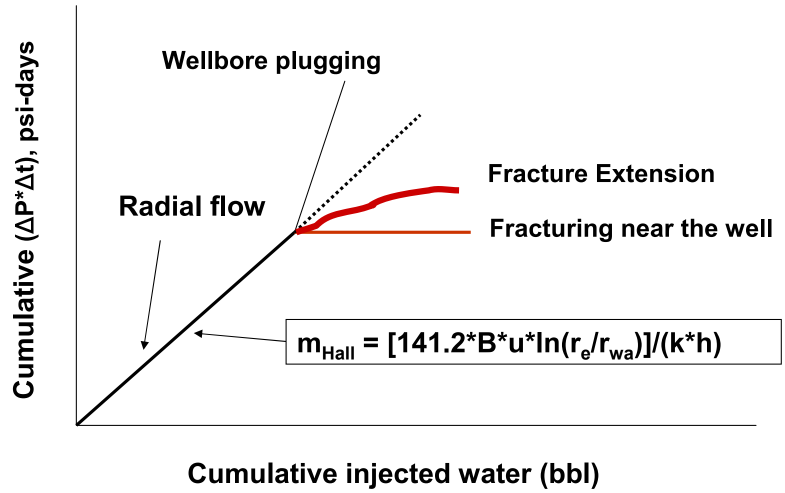
Example Step Rate Linear Plot



Other Uses of Injection Rate and Pressure Data

- **Monitor injection well behavior**
- **Data readily available in Class I wells**
- **Hall plot**
  - **Linear plot**
    - **x-axis: cumulative injected water, bbls**
    - **y-axis: $\Sigma(\Delta BHP * \Delta t)$, psi-day**
  - **Can be used to identify fractures**

Hall Plot

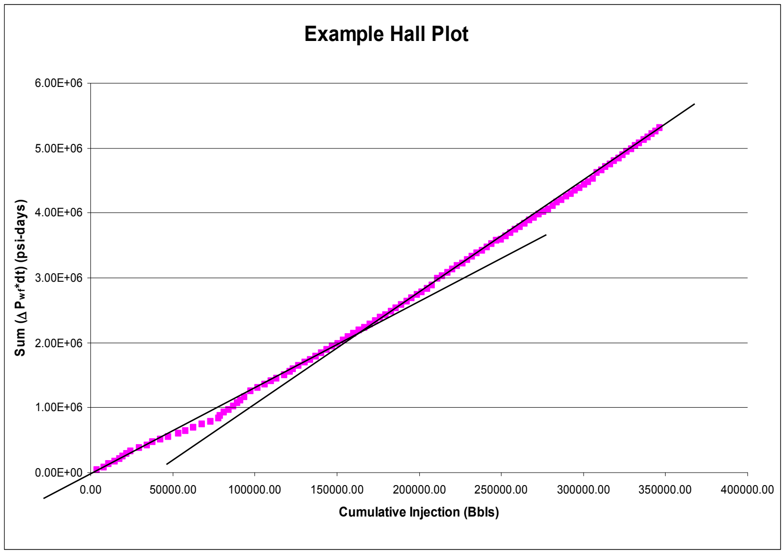


Wellbore plugging
Radial flow
Fracture Extension
Fracturing near the well
$m_{Hall} = [141.2*B*u*\ln(r_e/r_{wa})]/(k*h)$
Cumulative (ΔP*Δt), psi-days
Cumulative injected water (bbl)

Hall Plot Analysis

- Straight-line slope gives transmissibility: $$m_{Hall} = \frac{141.2\, B\, \mu \ln(r_e / r_{wa})}{k\, h}$$
- Slope changes indicate well conditions
  - Decrease in slope indicates fracturing (skin decrease)
  - Increase in slope indicates well plugging (skin increase)
  - Straight line indicates radial flow

Hall Plot Example



Hall Plot Limitations

- Type of pressure function used impacts the slope of the data plotted
- Cannot determine kh/μ and s independently from a single slope
- Pressure data is dependent on gauge quality and can be noisy