Acidizing - Dr, pour afshari

Lecture 1 : WELL STIMULATION

Outline

- Restricted flow
- Skin effect
- Formation damage

Ideal and Actual Flow

- changes in permeability near the wellbore
- changes in the radial flow geometry, caused by limited flow entry to the wellbore and flow convergence into the perforations
- high velocity effects

Skin Effect

- formation damage
- limited completion interval
- perforation effects
- high-velocity flow
- saturation blockage near the wellbore
- sand control
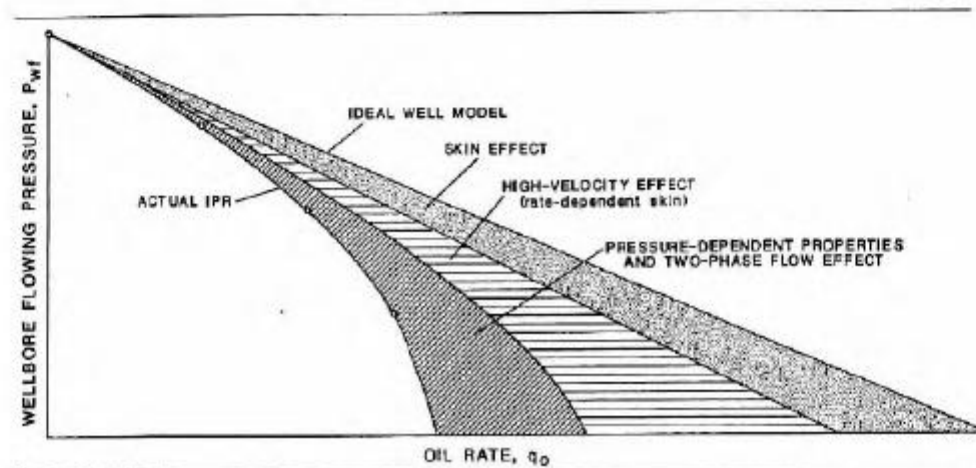
Formation Damage

- Near wellbore altered permeability
- Interaction between invaded fluid and the formation
  - Emulsion blockage
  - Water blockage
  - Change in rock wettability
  - Hydration and swelling of formation clays
  - Dispersion and migration of formation fines and grain cementation materials
  - Scaling (precipitation of inorganic salts)
  - Particle plugging of pores from entrained solids

Formation Damage Reduction

- Prediction of formation sensitivity
- Development of nondamaging drilling and completion fluids
- Development of high viscosity, polymer-based completion fluids with good fluid-loss control properties
- Development of effective bridging materials that can be easily removed before production startup
- Development of chemical agents that inhibit formation damage tendencies
- UBD techniques

Altered Permeability
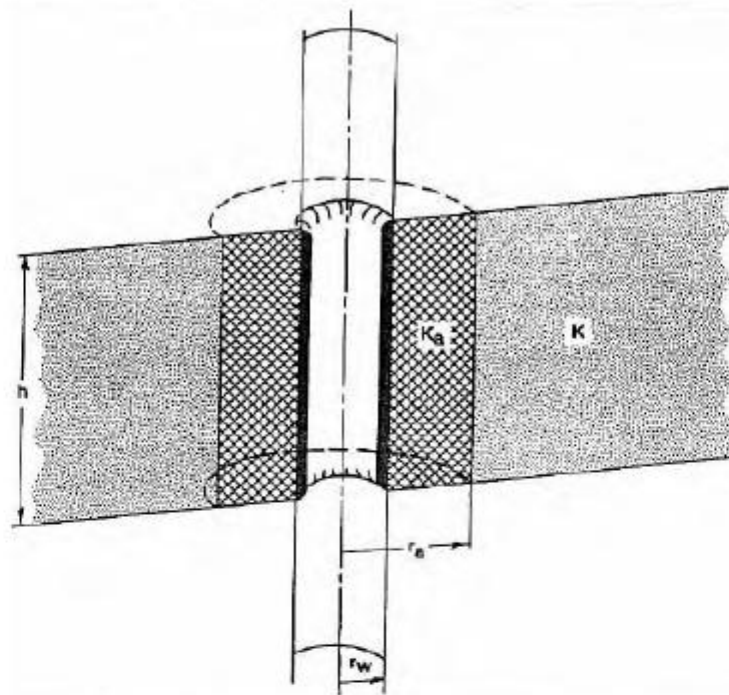
Example

- The formation around a well has a low permeability, 7 md.
  Producing thickness is 69 ft and average oil rate is 250 STB/D.

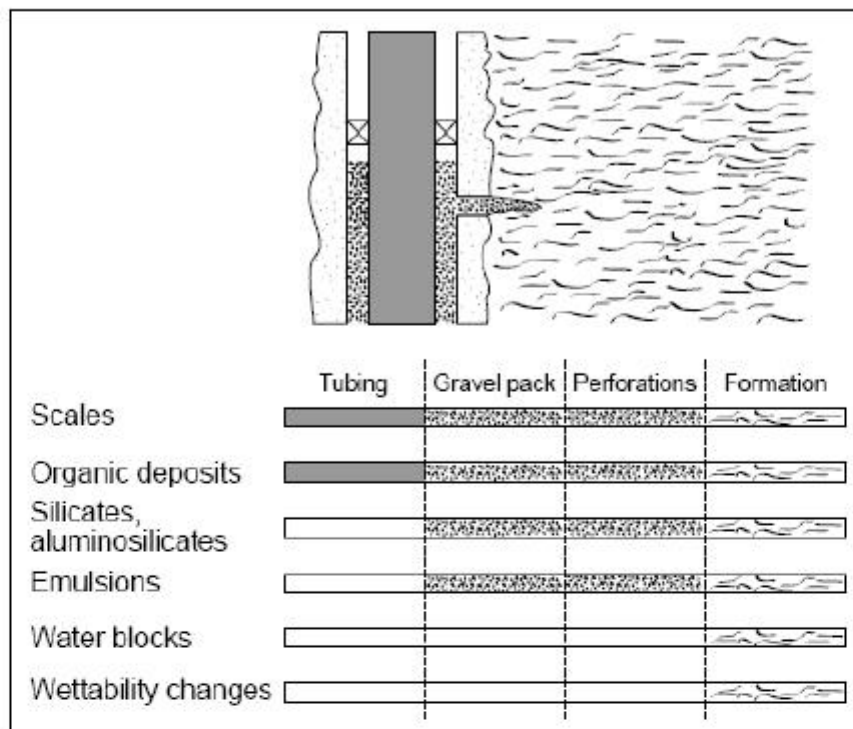|	
Total (producing) thickness h	69 ft
Oil formation volume factor B_o	1.136 bbl/STB
Oil viscosity μ_o	0.80 cp
Initial total compressibility c_{ti}	6.8×10^{-6} psi^{-1}
Porosity ϕ	0.039
Wellbore radius r_w	0.198 ft
Permeability k	7.0 md
Prestimulation skin s	+5.6
Poststimulation skin s	−3.7
Initial reservoir pressure p_i	4600 psia

- Calculate the fraction of pressure drop due to formation damage
  before stimulation. The drainage area is 80 acres.

- Calculate the altered zone permeability before the stimulation,
  assuming the value of damage radius equal to 1 ft.

- For a rate of 255 STB/D, calculate the stabilized flowing bottomhole
  pressure after stimulation

Lecture 2 : WELL STIMULATION

Formation Damage

- Near wellbore altered permeability
- Interaction between invaded fluid and the formation
  - Emulsion blockage
  - Water blockage
  - Change in rock wettability
  - Hydration and swelling of formation clays
  - Dispersion and migration of formation fines and grain cementation materials
  - Scaling (precipitation of inorganic salts)
  - Particle plugging of pores from entrained solids

Formation Damage Location

|	Tubing	Gravel pack	Perforations	Formation
Scales				
Organic deposits				
Silicates, aluminosilicates				
Emulsions				
Water blocks				
Wettability changes				

Formation Damage Investigation

- types of damage
- location of damage
- extent and screening of damage
- effect of damage on well production or injection

Natural and Induced Damages

- **Natural damages**
  - fines migration
  - swelling clays
  - water-formed scales
  - organic deposits such as paraffins or asphaltenes
  - mixed organic/inorganic deposits
  - emulsions.

- **Induced damages**
  - plugging by entrained particles such as solids or polymers in injected fluids
  - wettability changes caused by injected fluids or oil-base drilling fluids
  - acid reactions
  - acid by-products
  - iron precipitation
  - iron-catalyzed sludges
  - Bacteria
  - water blocks
  - incompatibility with drilling fluids.

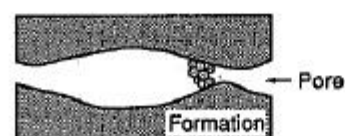# Fines Migration (Question 1)

- **What is the effect of fines migration on permeability?**
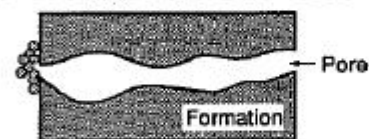
Cake Formation by Large Particles
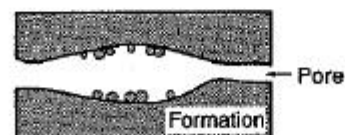
Surface Deposits of Adhering Particles

Plugging Type Deposits

Fines Migration (Question 2)

- **What is the migration reason?**
- Change is the chemical composition of the water
  - Salinity
  - Ionic composition
- Shear forces to the moving fluid

Fines Migration (Question 3)

- **Where does it occur?**
  - Surface area
  - Location

Particle Mineralogy	Major Components	Surface Area (m^2/g)
Quartz	Si, O	0.000015
Kaolinite	Al, Si, O, H	22
Chlorite	Mg, Fe, Al, Si, O, H	60
Illite	K, Al, Si, O, H	113
Smectite (montmorillonite)	Na, Mg, Ca, Al, Si, O, H	82

Fines Migration (Common Clays)
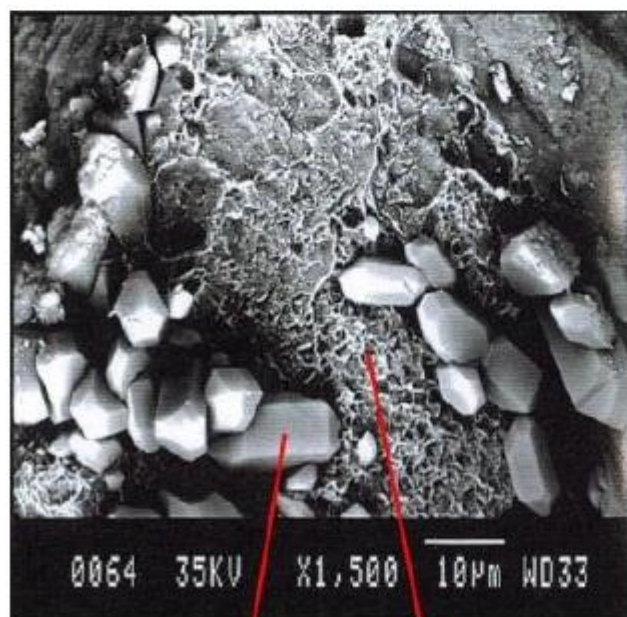
- **Authigenic**
- include quartz, chlorite and other pore-filling minerals or cements
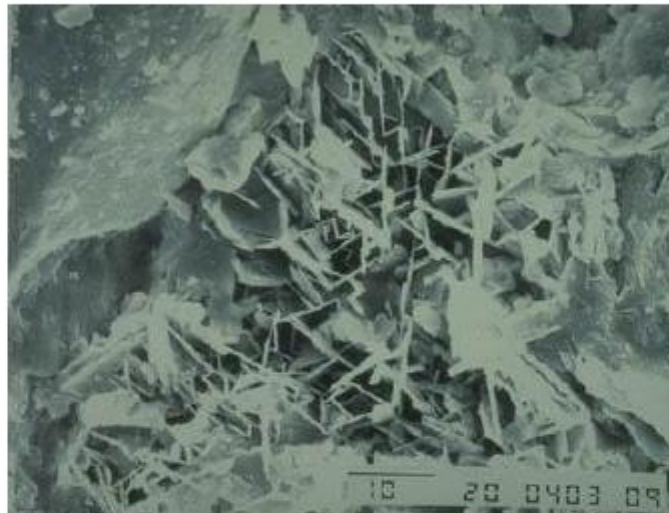
Swelling Clays

- [(1/2Ca,Na)0.7 (Al,Mg,Fe)4 (Si,Al)8 O20 (OH)47nH2O)]

  A group of clay minerals that includes montmorillonite. This type of mineral tends to swell when exposed to water. Bentonite includes minerals of the smectite group.

Quartz   Smectite clay

RESERVOIR CHARACTERISTICS AND DAMAGE AGENTS

Plates 8A and 8B: These two fields of view show highly leached **dolomite** and **calcite** (A and B, respectively) that have good access to open pore system. This mode of occurrence allows considerable interaction with solutions. **Exposure** of these cements to **HF-acid** would result in insoluble and irremovable calcium- and magnesium-**fluoride scales**. Also, the carbonate cements, in these fields of view, are **ferroan** in type. If exposed to **HCl-acid**, inherent iron could be released to the pore system, where it may precipitate as **iron gels**.

Plate 8C: This sandstone appears to have suffered extensive leaching of preexisting dolomite (circle). Mineral dissolution was conducive to great **improvement** in porosity and pore connectivity. Thus enhanced, the pore system allowed infiltration of **drilling-mud particulates** (arrows); accumulation of such particulates has been **detrimental** to **pore connectivity**.
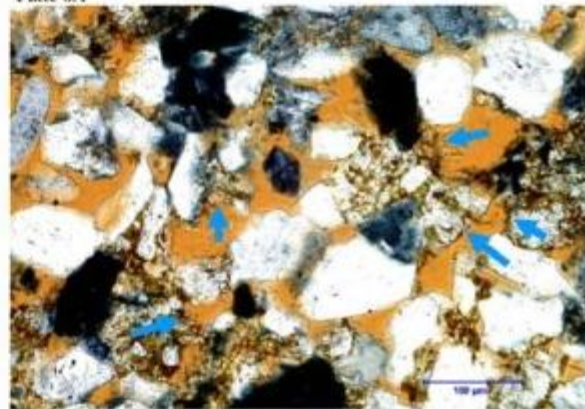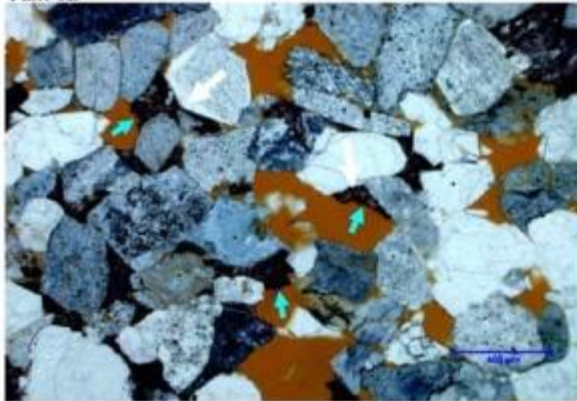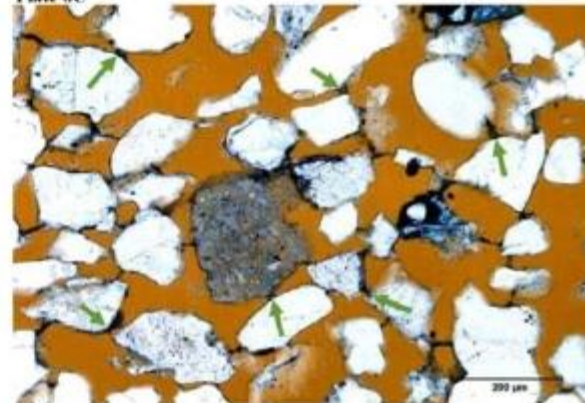
Plate 8A

Plate 8B

Plate 8C

RESERVOIR CHARACTERISTICS AND DAMAGE AGENTS

Plate 7A: Authigenic **kaolinite** (K) often is the main source for fines. In this field of view, such fines are present, both isolated (circle) and **exposed** to open pore system (arrows); the latter mode of occurrence presents potential for **fines migration**.

Plate 7B: Migratable **fines** may exist in different forms; two types are illustrated: a) 'loose' grains (blue circle) that are considerably **smaller** than adjacent framework grains, and b) **undissolved remnants** (orange circle) of partly leached grains; both 'fines' types are migratable.

Plate 7C: Fines also may result from partial leaching of **cement**, in this case calcite (light blue arrows). **Fragments** (yellow arrow) of in-situ microfractured grains have the potential to move, as well. Further **leaching** of a grain (marked) could have been conducive to the generation of mineral fines.
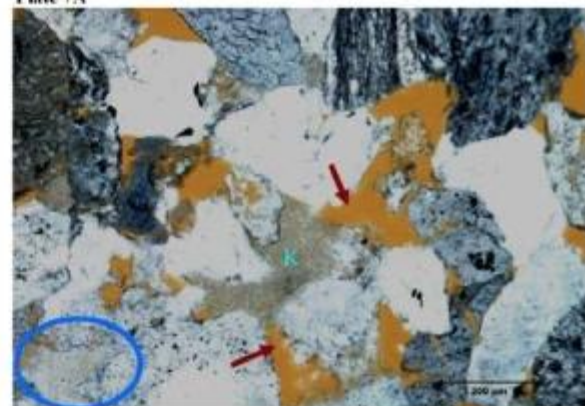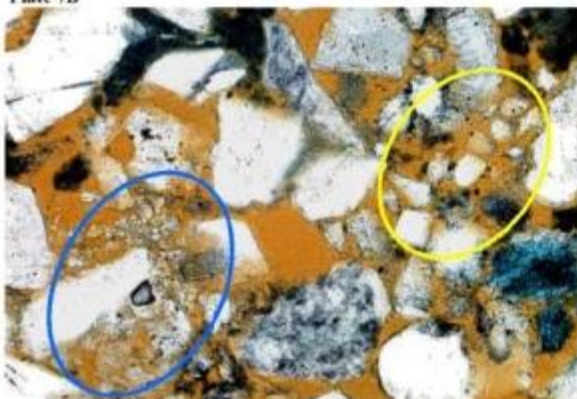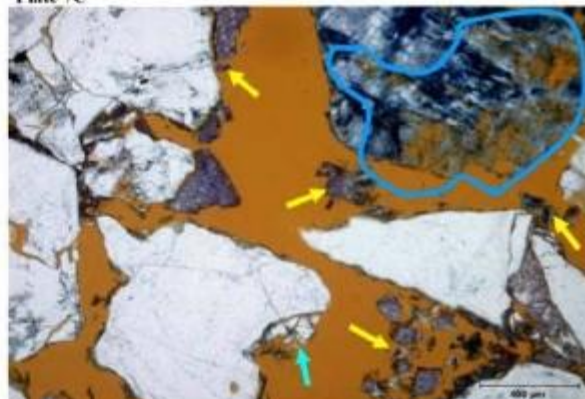
Plate 7A

Plate 7B

Plate 7C

RESERVOIR CHARACTERISTICS AND DAMAGE AGENTS

Plate 6A: Excellent 'homogeneous' porosity (blue). However, **pore connectivity**, in microscopic scale, is **heterogeneous**, increasing unproportionately (arrows) to the right of the marked area.

Plate 6B: Again, excellent porosity ('circles'), that is largely enhanced by mineral dissolution. Leaching, however, has also generated abundant **micropores** (arrows), which are **ineffective**, where liquid oil is present.

Plate 6C: Excessive mineral leaching may generate remnants (within 'circle') in the form of **mineral fines**, that are **migratable**.

Plate 6A
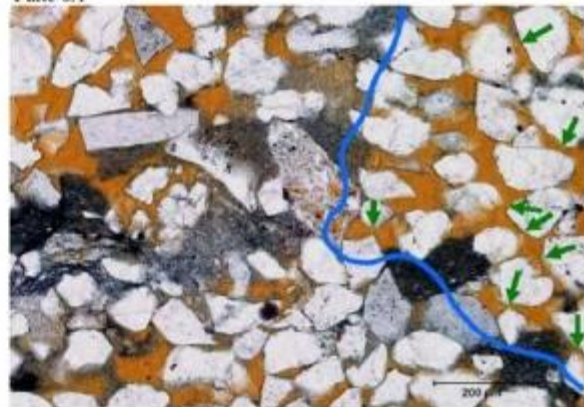
Plate 6B
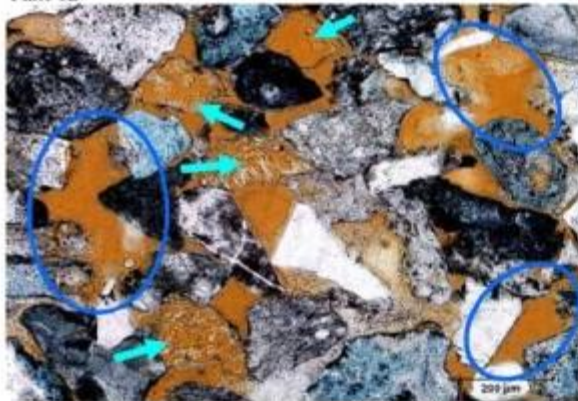
Plate 6C
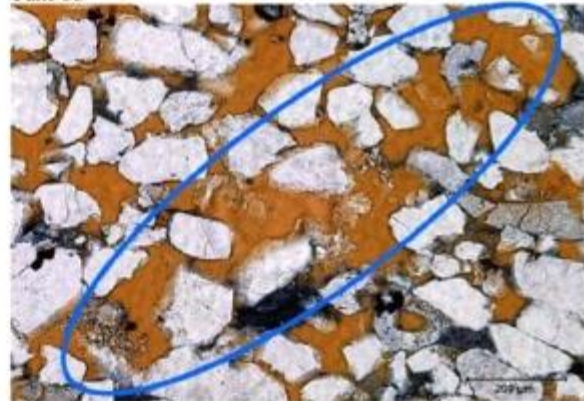
RESERVOIR CHARACTERISTICS

Pore-Throat Blocking and Fines Migration

Plate SEM 5A: 'Isopachous' coating of grains by authigenic chlorite has reduced porosity, but more importantly **blocked pore throats** (arrows).

Plate SEM 5B: An under-compact assemblage of kaolinite platelets and booklets. These clays have the potential to be dislodged and transported within the pore system, if fluid movement exceeds that of a "critical" flow rate, thus creating a **fines-migration** problem.

Plate SEM 5C: **Illite** fibers, or filaments (yellow arrows), are **fragile**; thus, they are prone to be broken off and **migrated**, similar to kaolinite, above. This pore also contains chlorite (green arrows).
Clays in these plates 'contain' **micropores**.

Plate SEM 5A
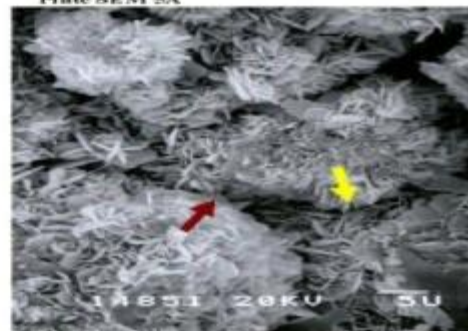
Plate SEM 5B
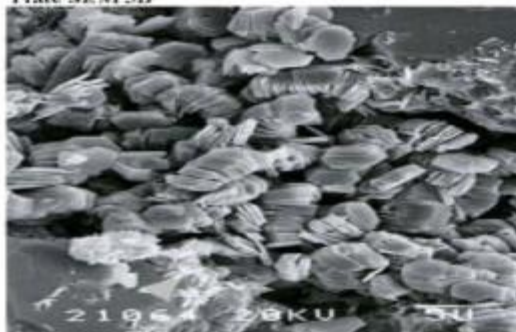
Plate SEM 5C
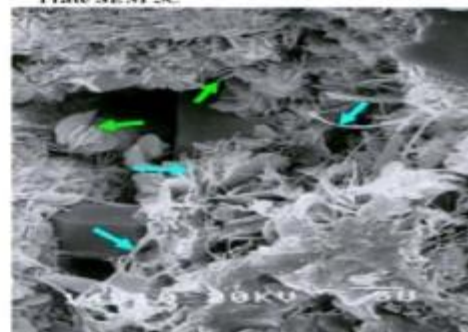
RESERVOIR CHARACTERISTICS

Swelling Clays

Plates SEM 6A, 6B And 6C: These fields of view illustrate the partial filling of pores and **bridging effect** (gray arrows) of mixed-layer clays (red arrows). Preexisting 'clean' intergranular pores have been volumetrically reduced by clays, and remnant open spaces are now largely subdivided into smaller spaces, mostly of **micropore** size. Mixed-layer clays, together with illite (green arrows), appear to have succeeded early-diagenetic authigenic chlorite (blue arrows).

Mixed-layer clays are **expandable**, when exposed to fresh water. **Clay swelling** increases with the percentage of **smectite** in these clays.

Plate SEM 6A

Plate SEM 6B
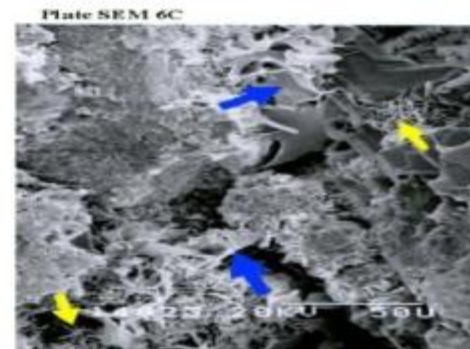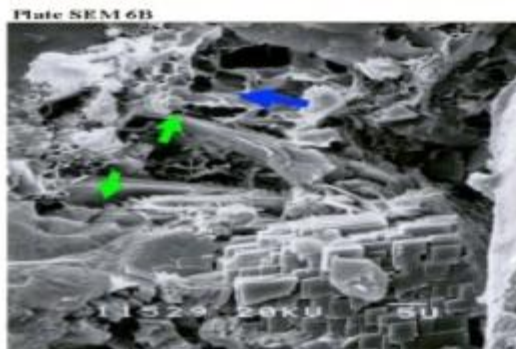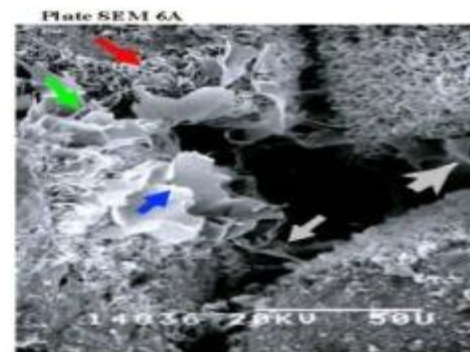
Plate SEM 6C

RESERVOIR DAMAGE

Swelling Clays

Plates SEM 7A and SEM 7B: These fields of view are illustrations of **pore-bridging** effect (arrow, in Plate A) by **swelling clays**. The original pores are subdivided into **micropores**.

Plate SEM 7C: Pore-bridging by accumulation of **drilling-mud** particulates (green arrow); such accumulations greatly reduce inter-pore connectivity (orange arrows).

Plate SEM 7A

Plate SEM 7B

Plate SEM 7C
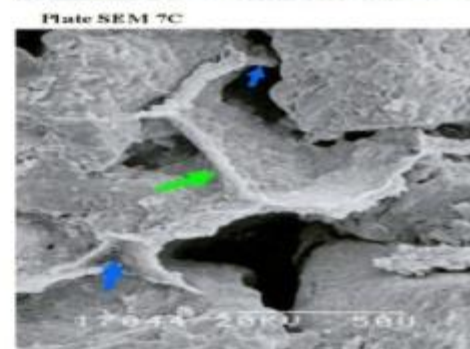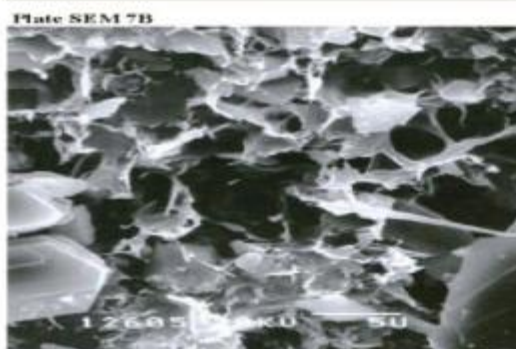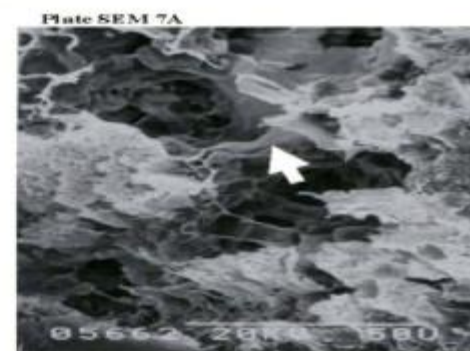
Scales

- The most common oilfield scales are calcium carbonate, calcium sulfate and barium sulfate.
- Anything that upsets the solution equilibrium may make scales
  - **Calcium carbonate or calcite ($CaCO_3$)**
  - **Gypsum**
  - **Barium sulfate ($BaSO_4$)**
  - **Iron scales**
  - **Chloride scales**

Organic Deposit

- Wax
- Asphaltine
  - The main reason is the reduction is pressure and temperature

Figure 14-5. *Thin section of a layered matrix deposit. The black layers are organic deposits, and the clear (white) layers are inorganic scales of mainly halite (NaCl).*

Emulsions

- Problem
  - High viscosity
  - High force is needed to overcome the yield stress

- Breaking mechanism
  - Stable/Unstable emulsions
  - Stabilizing forces
  - External solids, surfactants,…
  - Change in pH

Induced Particle Plugging

- Drilling fluids
  - clays, cuttings, weighting agents and loss-control materials, including polymers.
- Workover and stimulation fluids
  - bacteria and polymer residues
  - Kill fluids
- Stimulation fluids
- Acid treatments

Mud solids invasion

Wettability Alteration

- Wettability
  - flowing-phase quantity
  - coatings of natural and injected surfactants and oils
- Water wet/ oil wet
- Wettability alteration
- Effect of acid job

Acid Reactions and Acid Reaction By-products

- Damaging material from the tubing entering the formation
- Oil-wetting of the reservoir by surfactants, especially corrosion inhibitors
- Water blocks
- Asphaltene or paraffin deposition
- Sludges
- By-products precipitation
- Permeability impairment

Biological Damages

- Bacteria by-products
- Classifications
  - Aerobic bacteria, Anaerobic bacteria, Facultative bacteria
- Problems
  - sulfate-reducing bacteria
  - iron-oxidizing bacteria
  - bacteria that attack polymers in fracturing fluids and secondary recovery fluids.

Water Blocks

Figure: Relative permeability vs. Water saturation (% pore space), showing $k_{ro} = \dfrac{k_o}{k}$ and $k_{rw} = \dfrac{k_w}{k}$ curves, with "Irreducible water" and "Residual oil" regions marked.
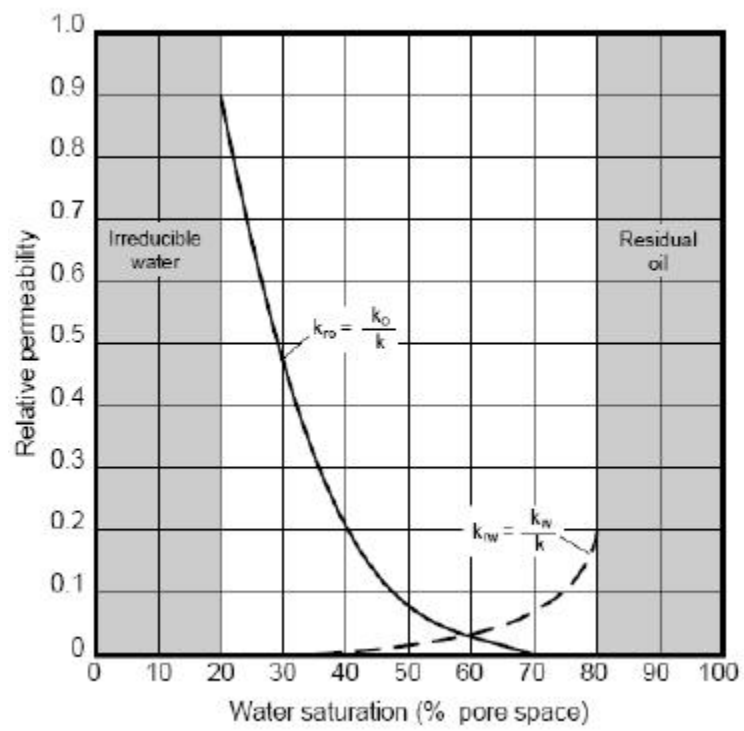
Lecture 3: Matrix Acidizing: Acid/Rock Interactions

Main activities of Stimulation

- Reservoir stimulation and artificial lift

- The main purpose of stimulation is to enhance the property value by the faster delivery of the petroleum fluid and/or to increase ultimate economic recovery.

- **Matrix stimulation** and **hydraulic fracturing** are intended to improve the natural connection of the wellbore with the reservoir, which could delay the need for artificial lift.

Introduction

- Initial oil/gas in place

- Flow rate from the reservoir to the wellbore

- Different production periods
  - Infinite acting (Transient)
  - Pseudo steady state
  - Steady state

Skin effect

- Skin effect

- Well productivity

- **Goal:**
  - Maximize the productivity index
    - Reducing skin effect ➡ Stimulation
    - Reducing the bottomhole pressure ➡ Artificial lift

Inflow Performance Relationship

- Period
  - Steady state
  - PSS
  - Transient
- Fluid flow
  - Oil single phase
  - Gas single phase
  - Two-phase
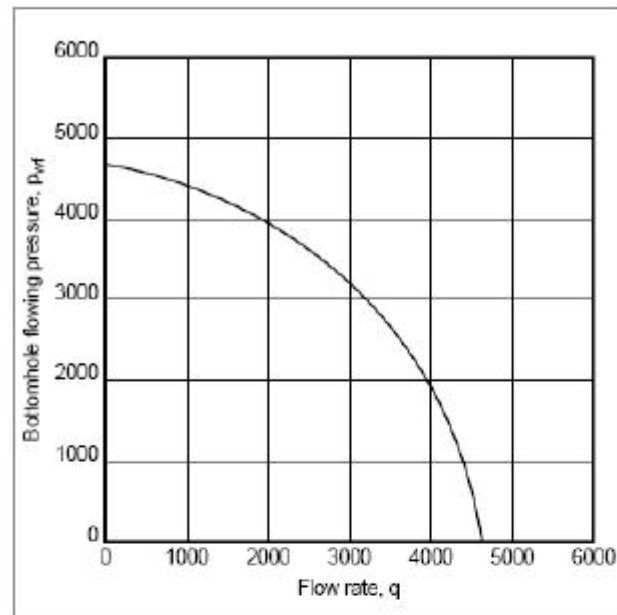
IPR for steady state period

- Single phase oil

$$q = \frac{kh(p_e - p_{wf})}{141.2 B\mu\left[\ln(r_e / r_w) + s\right]}$$

- Single phase gas

$$q = \frac{kh(p_e^2 - p_{wf}^2)}{1424\overline{\mu}\,\overline{Z}T\left[\ln(r_e / r_w) + s\right]}$$

- Two-phase

$$q_o = \frac{k_o h p_e\left[1 - 0.2\dfrac{p_{wf}}{p_e} - 0.8\left(\dfrac{p_{wf}}{p_e}\right)^2\right]}{254.2 B_o\mu_o\left[\ln(r_e/r_w) + s\right]}$$

Skin effect
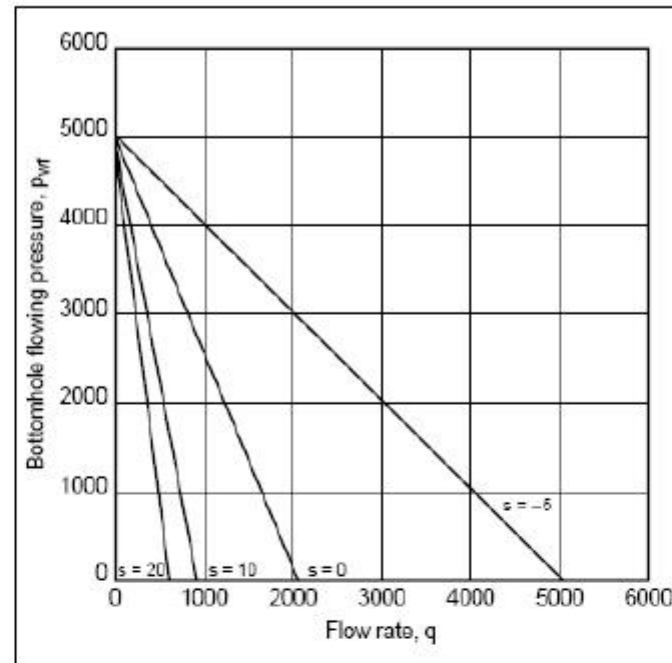
IPR for pseudo steady state period

- Single phase oil

$$q = \frac{kh(\bar{p} - p_{wf})}{141.2B\mu\left[\ln(0.472r_e/r_w) + s\right]}$$

- Single phase gas

$$q = \frac{kh\left[m(\bar{p}) - m(p_{wf})\right]}{1424T\left[\ln(0.472r_e/r_w) + s\right]}$$

- Two-phase

$$q = \frac{kh\bar{p}\left[1 - 0.2\dfrac{p_{wf}}{\bar{p}} - 0.8\left(\dfrac{p_{wf}}{\bar{p}}\right)^2\right]}{254.2B\mu\left[\ln(0.472r_e/r_w) + s\right]}$$
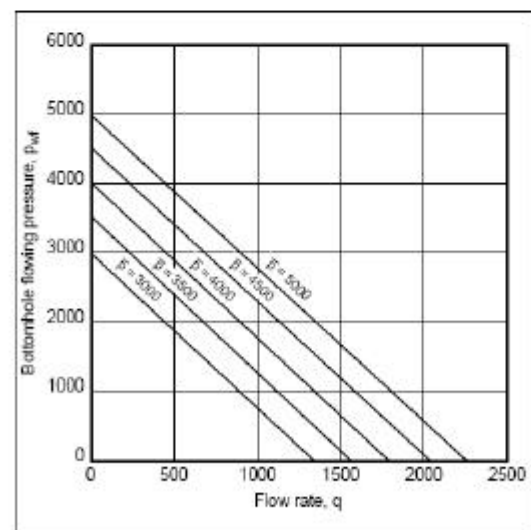
IPR for transient period

- Single phase oil

$$q = \frac{kh(p_i - p_{wf})}{162.6B\mu}\left(\log t + \log\frac{k}{\phi\mu c_t r_w^2} - 3.23\right)^{-1}$$

- Single phase gas

$$q = \frac{kh\left[m(p_i) - m(p_{wf})\right]}{1638T}\left(\log t + \log\frac{k}{\phi\mu c_t r_w^2} - 3.23\right)$$

- Two-phase

$$q = \frac{khp_i\left[1 - \dfrac{p_i}{P_{wf}} - \left(\dfrac{p_i}{P_{wf}}\right)^2\right]}{254.2B\mu\left(\log t + \log\dfrac{k}{\phi\mu c_t r_w^2} - 3.23\right)}$$
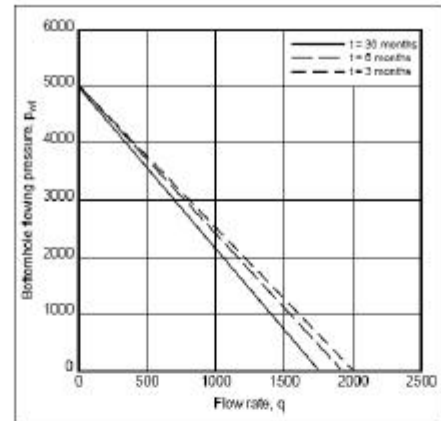
Stimulation - Acid

- A well test has indicated formation damage.
- An estimate has been made about the possible cause.
- Near well bore damage is indicated.
- What can be done about it?
- A matrix acid job may improve near well bore permeability.

Matrix Acid Treatments

- What is a matrix acid job?
- Injecting an acid solution below fracturing pressures.
- In this way the acid invades the matrix & is not injected down a created fracture.
- The objective is to dissolve some of the mineral present and hence recover or increase the permeability in the near wellbore vicinity.

Why Do They Work

- First of all, they don't always.
- Because the skin damage is hard to quantify.
- We do not really know how deep the damage is.
- And because reservoirs are made up of many minerals the acid reaction is hard to predict.
- Further, the reaction products and acid additives may create a damage all their own.

Commonly Used Acids

- HCl or hydrochloric acid is a strong mineral acid.
- HCl is used to treat carbonates in concentrations of 15 to 28% by weight (with additives).
- HCl is also used as a buffer and catalyst with HF acid in sandstone work.
- HF or hydrofluoric acid is also a strong mineral acid.
- It has unpleasant handling characteristics and is normally generated in situ.

Acid Types Continued

- HF mixtures rarely use more than 3% HF.
- Acetic acid is a mild organic acid.
- It is used in concentrations up to 10%.
- Due to its relatively high cost and lower dissolving power it is normally used as a perforating fluid.

Acid/Rock Interaction

- *Stoichoimetry of the acid-rock reaction*: the amount of rock dissolved for a given amount of acid.

- *The reaction kinetic*: the rates at which acids react with different minerals.

- *The diffusion rates*: how rapidly acid is transported to the rock surface.

Dissolving Power

- Acids can be compared using dissolving power .
- Dissolving power is related to the reaction stoichiometry.
- For HCl and CaCo3

$$2HCl + CaCO_3 \rightarrow CaCl_2 + CO_2 + H_2O$$

- This reaction requires 2 moles of HCl to dissolve 1 mole of CaCO3.

Primary Chemical Reactions

Table 16.1 *Primary Chemical Reactions in Acid Treatments*

Montmorillonite (Bentonite)-HF/HCl:	$Al_4Si_8O_{20}(OH)_4 + 40HF + 4H^+ \leftrightarrow 4AlF_2^+ + 8SiF_4 + 24H_2O$
Kaolinite-HF/HCl:	$Al_4Si_8O_{10}(OH)_8 + 40HF + 4H^+ \leftrightarrow 4AlF_2^+ + 8SiF_4 + 18H_2O$
Albite-HF/HCl:	$NaAlSi_3O_8 + 14HF + 2H^+ \leftrightarrow Na^+ + AlF_2^+ + 3SiF_4 + 8H_2O$
Orthoclase-HF/HCl:	$KAlSi_3O_8 + 14HF + 2H^+ \leftrightarrow K^+ + AlF_2^+ + 3SiF_4 + 8H_2O$
Quartz-HF/HCl:	$SiO_2 + 4HF \leftrightarrow SiF_4 + 2H_2O$
	$SiF_4 + 2HF \leftrightarrow H_2SiF_6$
Calcite-HCl:	$CaCO_3 + 2HCl \rightarrow CaCl_2 + CO_2 + H_2O$
Dolomite-HCl:	$CaMg(CO_3)_2 + 4HCl \rightarrow CaCl_2 + MgCl_2 + 2CO_2 + 2H_2O$
Siderite-HCl:	$FeCO_3 + 2HCl \rightarrow FeCl_2 + CO_2 + H_2O$

- The gravimetric dissolving power is the mass of mineral consumed by a given mass of acid.

$$\beta = \frac{\nu_{caco3} MW_{caco3}}{\nu_{HCl} MW_{Hcl}} = \frac{\text{lbs of } CaCO_3}{\text{lbs of } HCl}$$

$$\beta = \frac{(1)100}{(2)36.5} = 1.37 \text{ for } 100\% \text{ HCl}$$

- For 15% HCl solution:

$$\beta = 1.37(0.15) = 0.21 \frac{\text{lbs } CaCO_3}{\text{lbs } 15\% \text{ HCl}}$$

- For 15% HCL the volumetric dissolving power, X can be computed using the appropriate densities.

$$X = \beta \frac{\rho_{HCl}}{\rho_{CaCO3}} = 0.21(\frac{1.07(62.4)}{169}) = 0.082 \frac{ft^3 \; CaCO_3}{ft^3 \; 15\% \; HCl}$$

- X can be computed for any acid reaction.

Volumetric Dissolving Power

Dissolving Power of Various Acids[a]

			X			
Formulation	Acid	β_{100}	5%	10%	15%	30%
Limestone:	Hydrochloric (HCl)	1.37	0.026	0.053	0.082	0.175
CaCO$_3$	Formic (HCOOH)	1.09	0.020	0.041	0.062	0.129
$\rho CaCO_3 = 2.71$ g/cm^3	Acetic (CH$_3$COOH)	0.83	0.016	0.031	0.047	0.096
Dolomite:	Hydrochloric	1.27	0.023	0.046	0.071	0.152
CaMg(CO$_3$)−2	Formic	1.00	0.018	0.036	0.054	0.112
$\rho CaMg(CO_3)_2 = 2.87$g/cm^3	Acetic	0.77	0.014	0.027	0.041	0.083

Dissolving Power for Hydrofluoric Acid [a, b]

Acid concentration (wt%)	Quartz(Sio$_2$)		Albite (NaAlSi$_3$O$_8$)	
	β	X	β	X
2	0.015	0.006	0.019	0.008
3	0.023	0.010	0.028	0.011
4	0.030	0.018	0.037	0.015
6	0.045	0.019	0.056	0.023
8	0.060	0.025	0.075	0.030

Example

Calculating the HCl preflush volume

In sandstone acidizing treatments, a preflush of HCl is usually injected ahead of the HF/HCl mixture to dissolve the carbonate minerals and establish a low-pH environment. A sandstone with a porosity of 0.2 containing 10% (volume) calcite ($CaCO_3$) is to be acidized. If the HCl preflush is to remove all carbonates to a distance of 1 ft from the wellbore before the HF/HCl stage enters the formation, what minimum preflush volume is required (gallons of acid solution per foot of formation thickness)? The wellbore radius is 0.328 ft.

Reaction Rates

- The overall reaction rate is controlled by
  - The transport rate of the acid to the surface Either by diffusion Or convection
  - By the actual reaction rate at the surface.

Reaction Rate

- The rate of appearance in the solution of the species of interest in units of moles per second.
- A surface reaction rate depends on the amount of surface exposed to reaction, so these reactions are expressed on a per-unit surface area manner.
- The surface reaction rate of an aqueous species A reacting with mineral B is

$$R_A = r_A S_B$$

where R_A is the rate of appearance of A (moles/sec), r_A is the surface area-specific reaction rate of A (moles/sec-m^2), and S_B is the surface area of mineral B. When A is being consumed, the reaction rates, r_A and R_A, are negative.

Reaction Rate (rA)

- Depends on the concentration of the reacting species.

$$- R_A = E_f C_A^\alpha S_B$$

HCl Reaction Rates (With Carbonates)

- The reaction rate for HCl & calcite or dolomite is:

$$-r = E_f C_{HCl}^{\alpha}$$

$$E_f = E_f^o \exp\left(-\frac{\Delta E}{RT}\right)$$

15% HCl with CaCO3
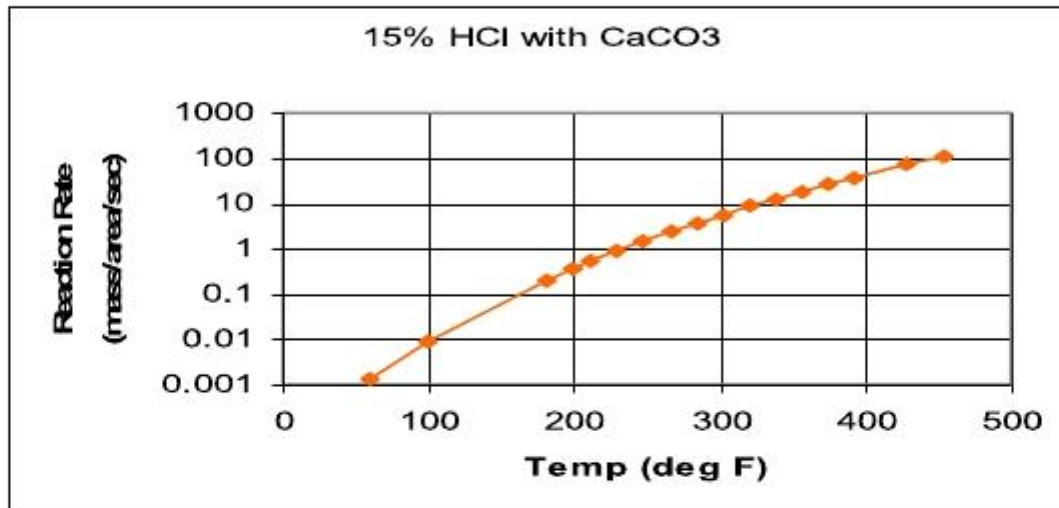
HCl Reaction Rates

Constants in HCl-Mineral Reaction Kinetics Models

Mineral	α	$E_f^o \left[\dfrac{\text{kg moles HCl}}{\text{m}^2\text{-s-(kg-moles HCl/m}^3\text{ acid solution)}^{\alpha}}\right]$	$\dfrac{\Delta E}{R}$ (K)
Calcite (CaCO$_3$)	0.63	7.314×10^7	7.55×10^3
Dolomite (CaMg(CO$_3$)$_2$)	$\dfrac{6.32 \times 10^{-4}T}{1 - 1.92 \times 10^{-3}T}$	4.48×10^5	7.9×10^3

HF Reaction Rates (with Sandstones)

- HF with quartzite, clays, & feldspars is:

$$-r = E_f(1 + K(C_{HCl})^\beta)C_{HF}^\alpha$$

$$E_f = E_f^o \exp(-\frac{\Delta E}{RT})$$

HF with Minerals
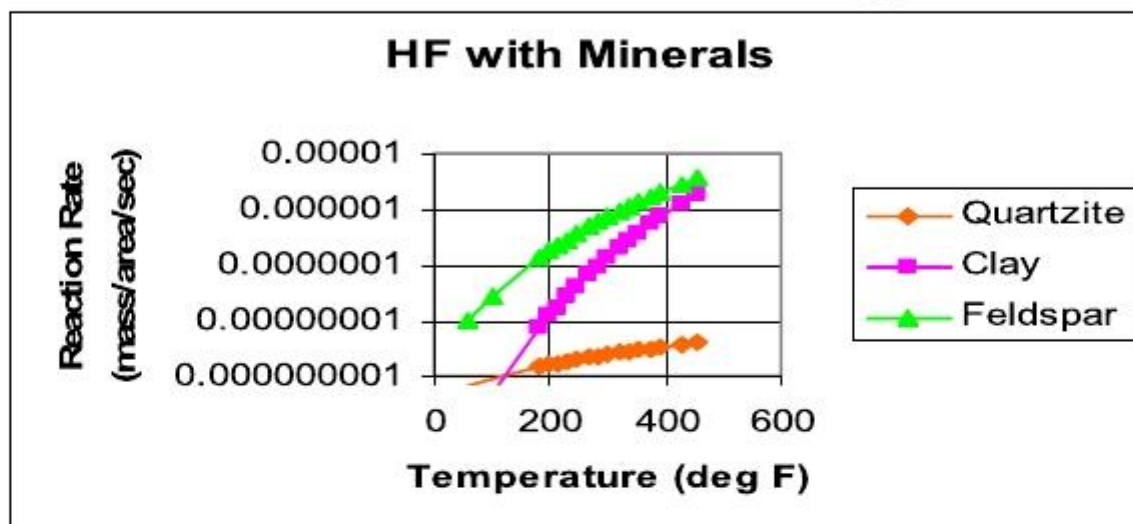
HF Reaction Rates (with Sandstones)

Table 13-6

Constants in HF-Mineral Reaction Kinetic Models

Mineral	α	β	K [(kg-mole HCl/m³)⁻ᵝ]	$E_f^o \left[\frac{kg\text{-}mole\ mineral}{m^2\text{-}sec\text{-}(kg\text{-}mole\ HF)/m^3\ acid]^\alpha}\right]$	$\Delta E/R(k)$
Quartz, SiO₂ᵃ	1.0	—	0	2.32×10^{-8}	1150
Orthoclase, K-Feldspar, KAlSi₃O₈	1.2	0.4	$5.66 \times 10^{-2} \exp(956/T)$	1.27×10^{-1}	4680
Albite, Na-Feldspar, NaAlSi₃O₈	1.0	1.0	$6.24 \times 10^{-2} \exp(554/T)$	9.50×10^{-3}	3930
Kaolinite, Al₄Si₄O₁₀(OH)₈	1.0	—	0	0.33	6540ᵇ
Sodium montmorillonite, Al₄Si₈O₂₀(OH)₄-nH₂O	1.0	—	0	0.88	6540ᵇ
Illite, K₀₋₂Al₄(Al,Si)₈O₂₀(OH)₄	1.0	—	0	2.75×10^{-2}	6540ᵇ
Muscovite, KAl₂Si₃O₁₀(OH)₂	1.0	—	0	0.49	6540ᵇ

Example

A 2-cm.-diameter disk of albite (Na-feldspar) is immersed in a 3 wt% HF, 12 wt% HCl solution at 50°C and rotated rapidly for 1 hr. The density of the acid solution is 1.075 g/cm³ and the density of the feldspar is 2.63 g/cm³. If the acid concentration remains approximately constant during the exposure period, what thickness of the disk will be dissolved and what mass of HF will be consumed?

Lecture 4: Sandstone Acidizing

Introduction

- The first step in planning of any matrix treatment should be a careful analysis of the causes of impaired well performance.
  - Measurement of the skin effect
    - Positive and zero skin effect in highly deviated wells
- If mechanical effects (perforation, partial penetration) do not explain the flow impairment, formation damage is indicated.
- In general, damage due to drilling mud invasion or fines migration can be successfully treated with acid.

Sandstone Acidizing General Procedure

- A preflush of 15% HCl with additives of at least 50 gal/ft to scrub away all CaCO3 ahead of the HF mix to prevent calcium flouride precipitants.

- Follow with correct HF/HCL mix at a minimum of 50 gal/ft or 25 gal/perforation with correct corrosion, anti-sludging, and iron sequestering additives.

- Post flush with 15% HCL with additives in a volume of at least twice the HF mixture volume. This prevents precipitants forming with displacement fluids.

- Flow or swab the acid volume out immediately to prevent damage.

Main Flush

Sandstone Acidizing

HCl solubility > 20%	Use HCl only
High permeability (100 md plus)	
High quartz (80%), low clay (<5%)	10% HCl–3% HF[a]
High feldspar (>20%)	13.5% HCl–1.5 HF[a]
High clay (>10%)	6.5% HCl–1% HF[b]
High iron chlorite clay	3% HCl–0.5% HF[b]
Low permeability (10 md or less)	
Low clay (<5%)	6% HCl–1.5% HF[c]
High chlorite	3% HCl–0.5% HF[d]

[a]Preflush with 15% HCl.

[b]Preflush with sequestered 5% HCl.

[c]Preflush with 7.5% HCl or 10% acetic acid.

[d]Preflush with 5% acetic acid.

Acid Job Design-Step 1

- We want to keep the job below fracturing pressures. So, we must estimate the fracture gradient.

- This may be known from area fracture jobs

$$FG = \frac{(ISIP + 0.052\rho_f D)}{D} \quad , \frac{psi}{ft}$$

ISIP = instantaneous shut in pressure in psi obtained from a frac job.

ρ_f = fluid density at the time of the ISIP in lb/gal.

D = datum depth (normally mid perforation) in feet.

Acid Job Design-Step 2

- Max BHP is now set as

$$p_{bd} = FG(D)$$

- Set the max injection rate using the PSS equation

$$p_{bd} - \bar{p} = \frac{141.2 q_i \mu}{kh} (\ln \frac{0.472 r_e}{r_w} + s)$$

- Solving for q
  - Where q is in bbl/min.

$$q_i = \frac{4.917 \times 10^{-6} kh(p_{bd} - \bar{p})}{\mu \ln(\frac{0.472 r_e}{r_w} + s)}$$

  - q is normally set at 90% as a safety factor.

$$q_{limit} = 0.9 q_i$$

Acid Job Design – Step 3

- Estimate the maximum surface pressure allowed

$$p_t = D(FG - HG) + FR$$

- Where FG is the frac gradient & HG is the hydrostatic gradient

$$HG = \frac{\rho_f}{8.33}(0.433) \quad , \mathrm{psi/ft}$$

$$R_e = 132,714.3 \frac{q_i \gamma}{d\mu}$$

$q_i = \text{injection rate (bbl/min)}$

$\gamma = \text{fluid specific gravity}$

$d = \text{tubular internal diameter (inches)}$

$\mu = \text{fluid viscosity (cp)}$

- FR is friction pressure & can be estimated based on Reynolds Number (Re).

Acid Job Design – Step 3

- A friction factor for turbulent flow in a smooth pipe is

$$f = \frac{0.0791}{R_e^{0.25}}$$

- FR is estimated

$$FR = \frac{1}{2}\bar{v}^2 \frac{D}{R_H} f \quad , \mathrm{psi}$$

$$FR = 7.51 \frac{q_i^2}{d^5} \frac{D\gamma}{R_e^{0.25}}$$

Sandstone Design - Step 4

- Step 4 is to choose the acid.
- A mixture of HCl and HF is required.
- If mud removal is the goal an acid mix like 6 ½% HCl and 1% HF might be chosen.
- A more careful design can be done by
  - Core flood test
    - Short core
    - Long core
  - Local experience is a good indicator, as is the shown table.

Acid Response Curve (An Example)

Berea sandstone
80°F - 100 psi

Percent of original permeability vs. Pore volumes of acid
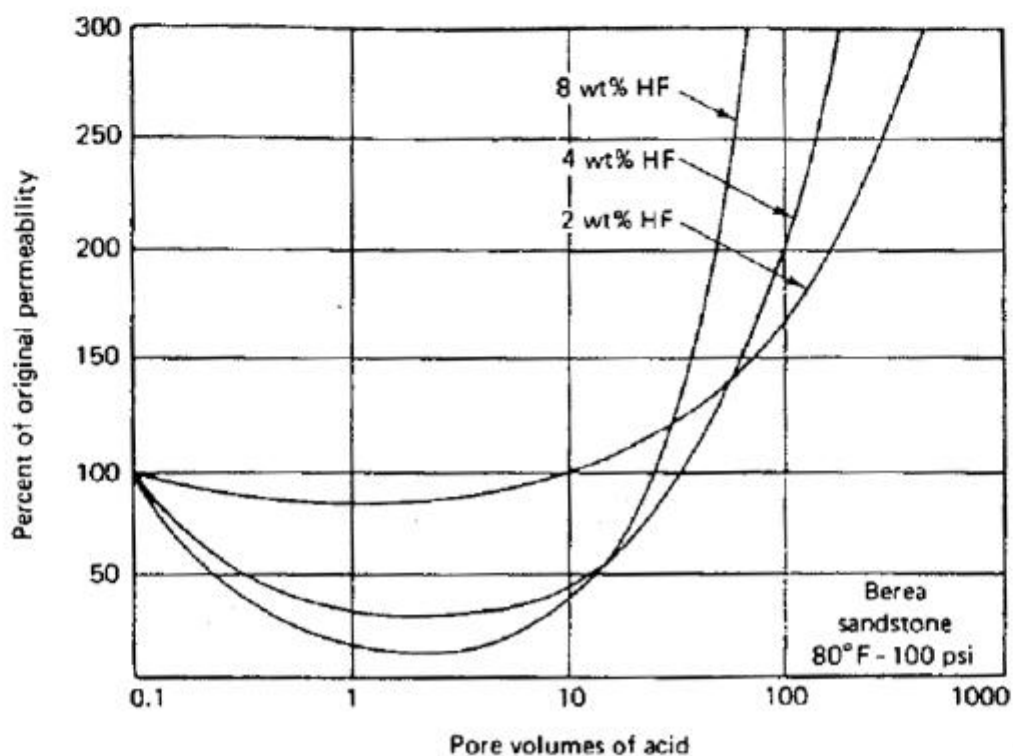
Acid Volume and Injection Rate

- Main parameters
  - Depth of the damage
  - Speed of the injection
    - The penetration of the acid
    - The precipitation

- We don't know the depth of the damage with any accuracy.
  - Acid response curve
  - Acidizing model

HF Volume to Use

- A most difficult choice because
  - Reactions are difficult to predict
  - Damage zone depth
- Best design is done with core flood work which is not always possible.
- Data can be extracted from literature, but they will probably not match the real reservoir rock.

HF Volume

- Predict using the two mineral model of Schechter and Hill. This lumps the minerals into a fast-reacting and a slow-reacting group.

$$\frac{\partial(\phi C_{HF})}{\partial t} + u\frac{\partial C_{HF}}{\partial x} = -\left(S_F^* V_F E_{f,F} + S_S^* V_S E_{f,S}\right)(1-\phi)C_{HF}$$

$$\frac{\partial}{\partial t}[(1-\phi)V_F] = \frac{-MW_{HF}S_F^* V_F \beta_F E_{f,F}C_{HF}}{\rho_F}$$

$$\frac{\partial}{\partial t}[(1-\phi)V_S] = \frac{-MW_{HF}S_S^* V_S \beta_S E_{f,S}C_{HF}}{\rho_S}$$

Dimensionless Model

$$\frac{\partial \psi}{\partial \theta} + \frac{\partial \psi}{\partial \epsilon} + \left(N_{Da,F}\Lambda_F + N_{Da,S}\Lambda_S\right)\psi = 0$$

$$\frac{\partial \Lambda_F}{\partial \theta} = -N_{Da,F}N_{Ac,F}\psi\Lambda_F$$

$$\frac{\partial \Lambda_S}{\partial \theta} = -N_{Da,S}N_{Ac,S}\psi\Lambda_S$$

where the dimensionless variables are defined as

$$\psi = \frac{C_{HF}}{C_{HF}^0}$$

$$\Lambda_F = \frac{V_F}{V_F^0}$$

$$\Lambda_S = \frac{V_S}{V_S^0}$$

$$\epsilon = \frac{x}{L}$$

$$\theta = \frac{ut}{\phi L}$$

N_{Da}, the Damkohler number, and N_{Ac}, the acid capacity number.

Dimensionless Numbers (for the fast-reacting minerals)

$$N_{\text{Da},F} = \frac{(1 - \phi_0) V_F^0 E_{f,F} S_F^* L}{u}$$

$$N_{\text{Ac},F} = \frac{\phi \beta_F C_{\text{HF}}^0 \rho_{\text{acid}}}{(1 - \phi) V_F^0 \rho_F}$$

Acid and Fast-Reacting Mineral Concentration Profile
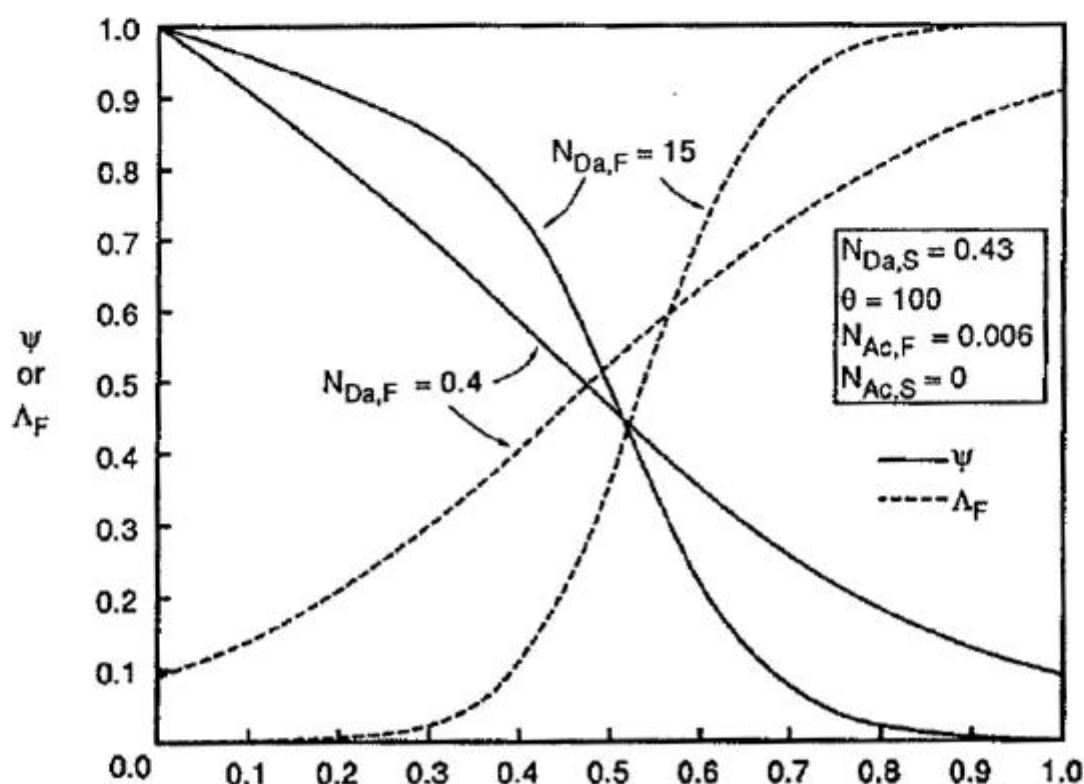
HF Volume

- To predict HF volume we need
  - lab derived values from a linear core flood by the acid of choice.
  - The linear Damkohler number and the acid capacity number.
  - Finally a choice is made for flow geometry

The Location of the Front

$$\theta = \frac{\exp(N_{Da,S}\epsilon_f) - 1}{N_{Ac,F} N_{Da,S}} + \epsilon_f$$

The slow group defines how much acid is available.
The fast group defines how fast the acid reaction can move.

The dimensionless acid concentration behind the front is

$$\psi = \exp(-N_{Da,S}\epsilon)$$

Dimensionless Groups in Sandstone Acidizing Model

Flow Geometry	ϵ	θ	$N_{Da,S}$
Linear	$\frac{x}{L}$	$\frac{ut}{\phi L}$	$\frac{(1-\phi)V_S^0 E_{f,S} S_S^* L}{u}$
Radial	$\frac{r^2}{r_w^2} - 1$	$\frac{q_i t}{\pi r_w^2 h\phi}$	$\frac{(1-\phi)V_S^0 E_{f,S} S_S^* \pi r_w^2 h}{q_i}$
Ellipsoidal	Penetration from the tip of the perforation $\frac{1}{3}\bar{z}^3 - \bar{z} + \frac{2}{3}; \bar{z} = \frac{z}{l_{perf}}$ Penetration adjacent to the wellbore $\frac{1}{3}\left(\bar{x} + \frac{1}{\bar{x}+\sqrt{\bar{x}^2+1}}\right)^3 - \frac{1}{3}$ $\bar{x} = \frac{x}{l_{perf}}$	$\frac{q_{perf} t}{2\pi l_{perf}^3 \phi}$	$\frac{2\pi (1-\phi)l_{perf}^3 S_S^* V_S^0 E_{f,S}}{q_{perf}}$

Note: Ψ, Λ, and $N_{Ac,f}$ are the same for all geometries.

Ellipsoidal Flow Geometry
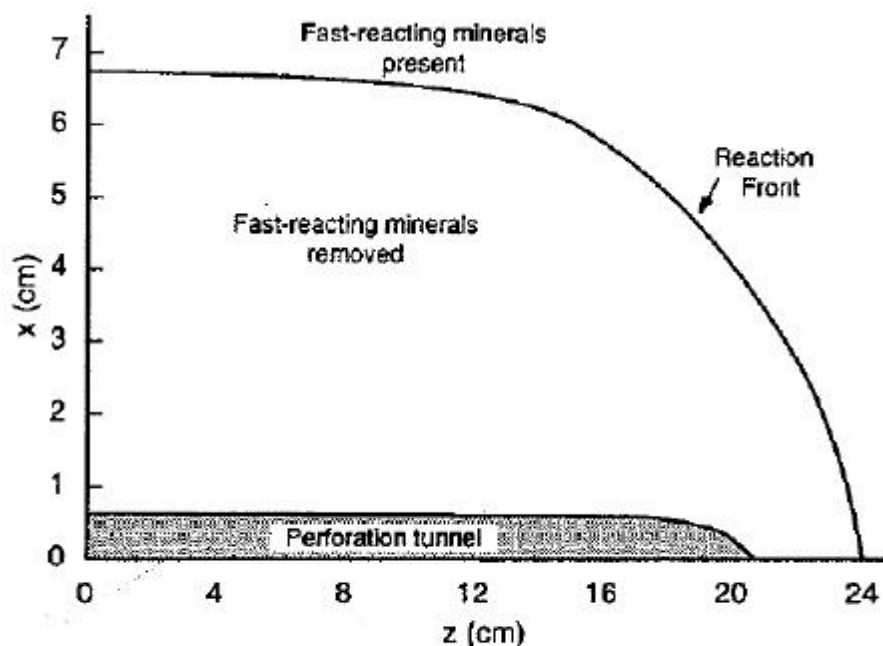
Figure 14-3
Ellipsoidal flow around a perforation. (*From Schechter, 1992.*)

HF Volume Prediction (Radial Flow Geometry)

$$\varepsilon = \frac{r^2}{r_w^2} - 1$$

is the dimensionless penetration

$$r = r_w + P$$

where P is inches of penetration

and dimesionless rection front position

$$\theta = \frac{\exp(\varepsilon N_{DA,r}) - 1}{N_{AC,F}(N_{DA,r})} + \varepsilon$$

HF Volume

- The Damkohler number for the slow mineral reaction and the Acid capacity number for the fast mineral reaction, both from the linear core test.

- The linear Damkohler number can be related to radial flow as follows:

$$N_{DA,r} = 6.717(N_{DA,L})\frac{r_w^2 h}{q_i}\left(\frac{u}{L}\right)_{core}$$

q_i is in bbl/min

u is flux in ft/min

L is core length in inches

HF Volume

- Finally the acid volume in gal/ft is

$$\frac{V}{h} = 23.5\theta r_w^2 \phi$$

- The generally accepted minimum volumes are 25 gal/perforation or 50 gal/ft of formation thickness.

Example

Determining $N_{Ac,F}$ and $N_{Da,S}$ from laboratory data

The effluent acid concentration measured in a core flood of a 0.87 in. diameter by 1.57-in.-long Devonian sandstone core with 1.5 wt% HF, 13.5 wt% HCl by da Motta et al. (1992a) is shown in Fig. 14-4. The acid flux was 0.346 cm/min (0.0114 ft/min). Determine $N_{Da,S}$ and $N_{Ac,F}$ from the data.
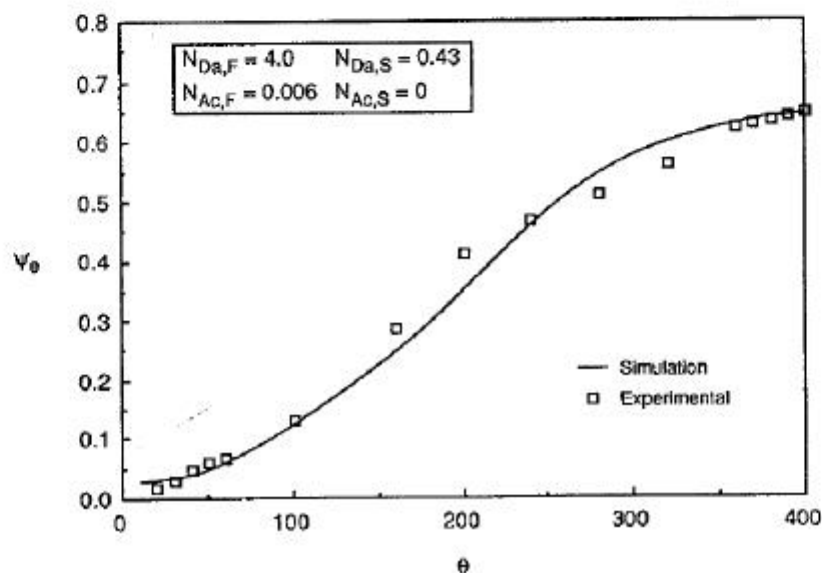
Example

Acid volume design for radial flow

Using the acid capacity and Damkohler numbers from Example 14-1, determine the acid volume (gal/ft) needed to remove all fast-reacting minerals to distances of 3 in. and 6 in. from a wellbore of radius 0.328 ft., assuming that the acid flows radially into the formation, such as would occur in an open-hole completion. The acid injection rate is 0.1 bbl/min-ft of thickness, and the porosity is 0.2.

Lecture 5: Sandstone Acidizing

HCL Preflush

- Very important
- Removes CaCO3, Na, and K from HF effected area. Helps prevent precipitants.
- Predict volume required using same procedure

$\varepsilon = \dfrac{r^2}{r_w^2} - 1$ is the dimensionless penetration

$N_{AC,HCL} = \dfrac{\phi \beta C_{HCL} \rho_{HCL}}{(1-\phi)V_{CO3}\rho_{CO3}}$ is the dimensionless acid number for HCl where

V_{CO3} is the volume fraction of CaCO3 in the rock,

$\beta = 100\%$ gravimetric dissolving power of HCl

$C_{HCl} = $ HCl concentraion as a fraction

$\rho_{HCl} = $ specific gravity of the acid, $\rho_{CO3} = $ specific gravity of CaCO3 (2.71 g/cc)

$N_{AC,HCL} = \dfrac{0.5055\phi\beta\rho_{HCl}}{(1-\phi)V_{CO3}}$

the dimensionless reaction front position is

$$\theta = \varepsilon(1 + \frac{1-\phi}{\phi}V_{CO3} + \frac{1}{N_{AC,HCL}})$$

- The preflush volume is in gal/ft.
- In the absence of data to use in the calculation use a preflush of 50 gal/ft.

$$\frac{V}{h} = 23.5\theta r_w^2 \phi$$

Example

Preflush volume design for a perforated completion

Calculate the volume of 15 wt% HCl preflush needed to dissolve all carbonates to a distance of 1 ft beyond the tip of a 6-in.-long, 0.25-in.-diameter perforation if there are 4 shots/ft. The density of the acid solution is 1.07 g/cm³. The formation contains 5 vol% CaCO₃ and no other HCl-soluble minerals and has an initial porosity of 0.2.

HF Postflush

- The displacement of the HF acid mixture is separated by a postflush fluid designed to keep the HF acid from contacting a damaging flush fluid. The postflush volume must be at least twice the HF volume and is displaced to the perforations with the flush fluid.

- Oil reservoir post flush is either 15% HCL or diesel, followed by field brine or 2 % KCL.

- In gas reservoirs or injection wells it is 15% HCL followed by field brine or 2% KCL.

Flow Back and fluid notes

- The HF job must be flowed back ASAP.

- If the well will not flow a swab unit or coil tubing jet must be used ASAP to unload the acid from the well.

- Final flush water, especially field brines, needs to be clean. No need to introduce any more fines or emulsions.

Additives (Corrosion Inhibitors)

- HCl + Steel
- Sensitive to temperature and treatment time
- A maximum weight loss of 0.05 lb/ft2 of tubing area is acceptable. (removal of 0.001 in of the tubing wall thickness)
- Organic compounds containing polar groups that are attracted to the metal surface.
- The time of inhibitor depend on the bottom hole temperature, the type of the steel and the expected treatment time.

Additives (Sequestering Agents)

- Both the ferrous (Fe ++) and ferric (Fe+++) forms of iron will precipitate as the acid spends and pH increases.
- Especially when Fe+++ are present in the near wellbore region, Fe(OH)3 may precipitate which is the most insoluble form.
- The main source of Fe+++ is the acid reacting with rust in the surface tanks, flowlines and tubing. The Fe++ is mainly derived from the formation minerals.

Additives (Sequestering Agents)

- A number of sequestering (solubilising) agents are available to increase the solubility of irons by forming soluble complexes.
  - Citric acid
  - EDTA (Ethylene Diamine Tetracetric Acid)
- Another approach to prevent ferric hydroxide precipitation is to reduce the Fe^{+++} to Fe^{++} by Erythobic acid or Ascorbic acid.

Additives (Surfactants)

- To prevent the formation of emulsions, to speed cleanup of spent acid, and to prevent sludge formation.

Fluid Placement and Diversion

- Proper placement of the acid
- The acid will tend to flow primarily into the highest-permeability zones, leaving lower-permeability zones untreated.
- The damage may not be distributed uniformly.
- The acid should be diverted by
  - Mechanical means
  - Ball sealers
  - Diverting agent
  - Gels and Foams

Mechanical Acid Placement

- Isolate individual zones
- Control of the point of fluid injection by use of retrievable bridge plugs placed in packers set between completion zones, dual packers on a work string (selective placement tool), sequential perforation,…

(A) Zones A and B to be selectively treated

(B) Install packer between Zones A and B using wireline

(C) Isolate zones A and B from the rest of the well using a retrievable bridge plug

(D) Run work string and set inflatable packer between zones A and B. Treat zone A by pumping down work string

(E) Treat zone by zone by pumping down workstring/casing annulus

(F) Unset packer and recover workstring. Recover retrievable bridge plug. Return well to production

Selective Placement

Ball Sealers

- Rubber-coated balls that are designed to seat in the perforations in the casing, thereby diverting injected fluid to other perforations.

- The balls are used whenever it is desired to change fluid injection from one zone to another.

- The density of the ball may be chosen so that it is buoyant or sinks in the treatment fluid, this controls whether the ball is produced back to the surface after the treatment is finished.

Ball Sealers

A   B   C   D   E
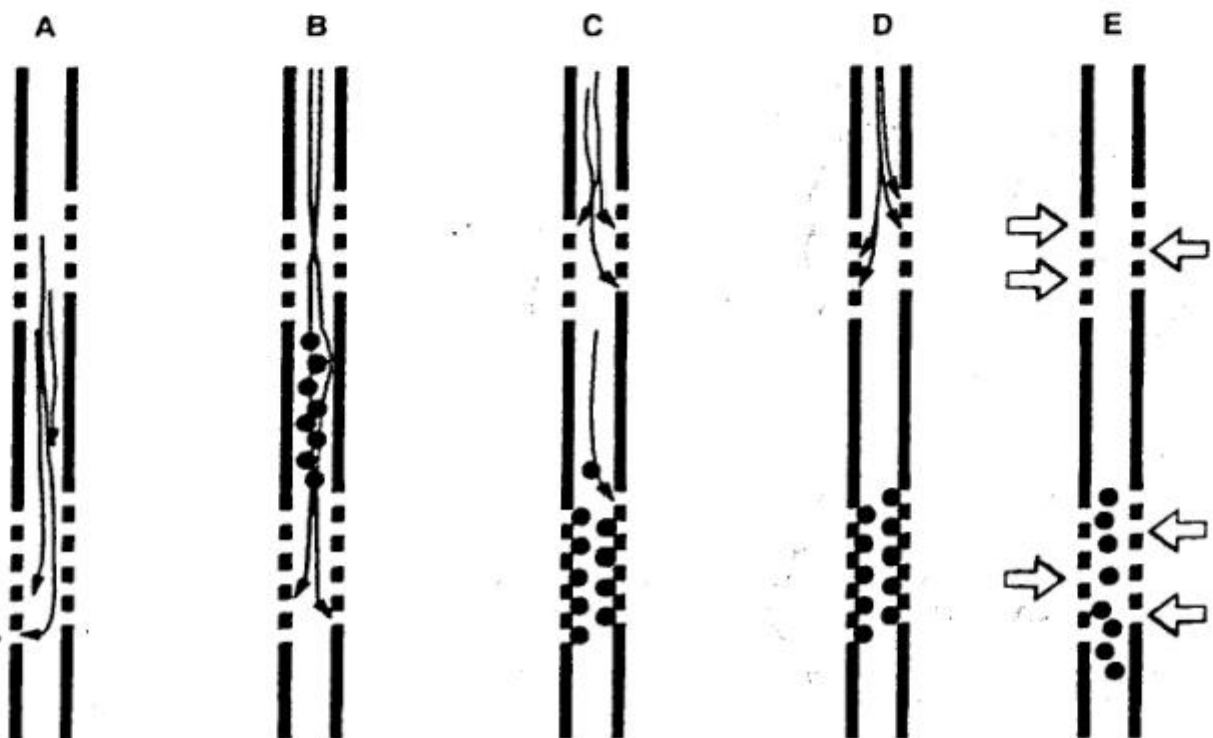
Viscous Fluids (Gels and Foams)

- They increase the flow resistance in the layer taking excessive amounts of treatment fluid so that the fluid is diverted into a new layer.

- The viscous fluid should be highly shear thinning i.e. its viscosity increases rapidly as the flow velocity decreases at the greater depths of injection.

- This allows it to form a viscous plug.

Pack the Perforation (Particulates, Film Forming Chemicals)

Casing
Cement
Thin, impermeable (– 1mD) film on perforation wall
Formation

Granular Diverter (– 200mD) packs perforation
Formation
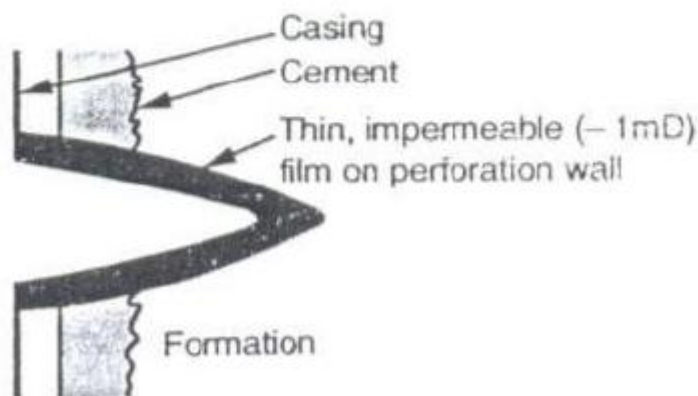
Diversion with "Film Forming" chemicals
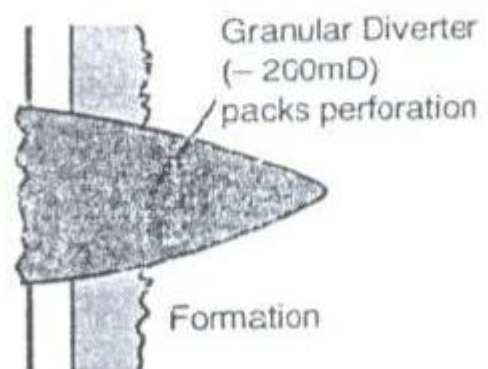
Diversion with Granular particulates

Diverting Agents

- The most common

- Fine particles that form a relatively low-permeability filter cake on the formation face.

- The pressure drop through this filter cake increases the flow resistance, diverting the acid to other parts of the formation where less diverting agent has been deposited.

- To form a low permeability filter cake, small particles and a wide range of particle sizes are needed. To ensure cleanup, materials that are soluble in oil, gas, and water are chosen.

Properties

- Being prepared in the required range of particle sizes

- Be stable in the treatment fluid

- Disappear (dissolve in the produced fluids) from the perforation so that it becomes fully open to flow once the well is returned ti production

- Be non-toxic, cheaply and readily available.

Common Diverters

Table 14-6

Summary of Particulate Diverters with Recommended Concentrations

Diverting Agent	Concentration
Oil-soluble resin or polymer	0.5 to 5 gal/1000 gal
Benzoic acid	1 lb_m/ft of perforations
Rock salt	0.5 to 2 lb_m/ft (do not use with HF acid)
Unibeads (wax beads)	1 to 2 lb_m/ft
Naphthalene flakes or moth balls	0.25 to 1 lb_m/ft (do not use in water-injection wells)

Lecture 6: Carbonate Acidizing

Introduction

- Chemistry of the process is simpler than sandstone, but the physics is more complex.
- In sandstone, the surface reaction rates are slow and a uniform acid front moves through the porous medium.
- In carbonates, surface reaction rates are very high, so mass transfer often limits the overall reaction rates, leading to non-uniform dissolution patterns.

Acid Type

- Decide on acid type.

- Normally HCL, either 15% or 28%.

- Use the stronger acid, especially above 200 deg F, unless the reservoir liquids form a sludge at this concentration.

- Obtain an liquid sample (oil, condensate, water) and do the lab work to test for sludging.

Wormholes

- Often, a few large channels, called wormholes, are created, caused by the non-uniform dissolution of limestone by HCl in a linear core flood.
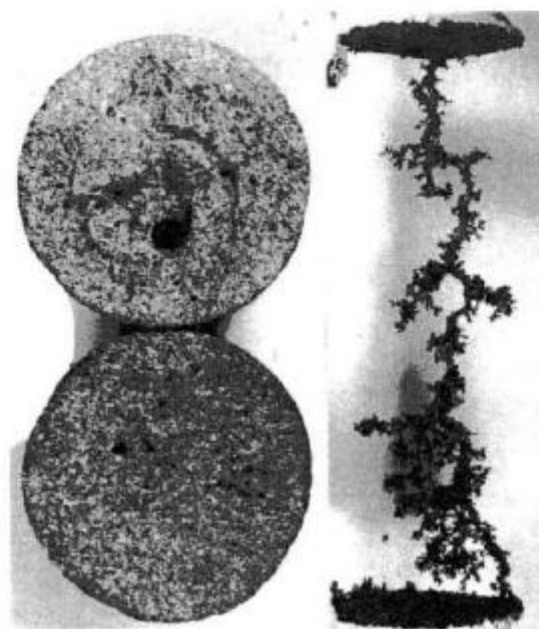
Wormholes

Wormhole Formation and Growth

- The large pores grow at a rate higher than the smaller pores, so that a large pore receives a larger proportion of the dissolving fluid, becoming a wormhole.
- Two mechanisms are important
  - Mass transfer (diffusive flux)
  - Surface reaction rate (flux of molecular consumed)

$$P = \frac{u_d}{u_s}$$

$$P = \frac{D}{E_f r C^{n-1}}$$

Mass Transfer-Limited Reactions

- The natural tendency for wormholes to grow in this case can be demonstrated by

$$\frac{dA}{dt} = \Psi A^{1-n}$$

For a single pore:
0.5 in surface reaction limited
-1 in mass transfer limited

Pore growth function of time

Cross sectional area of the pore
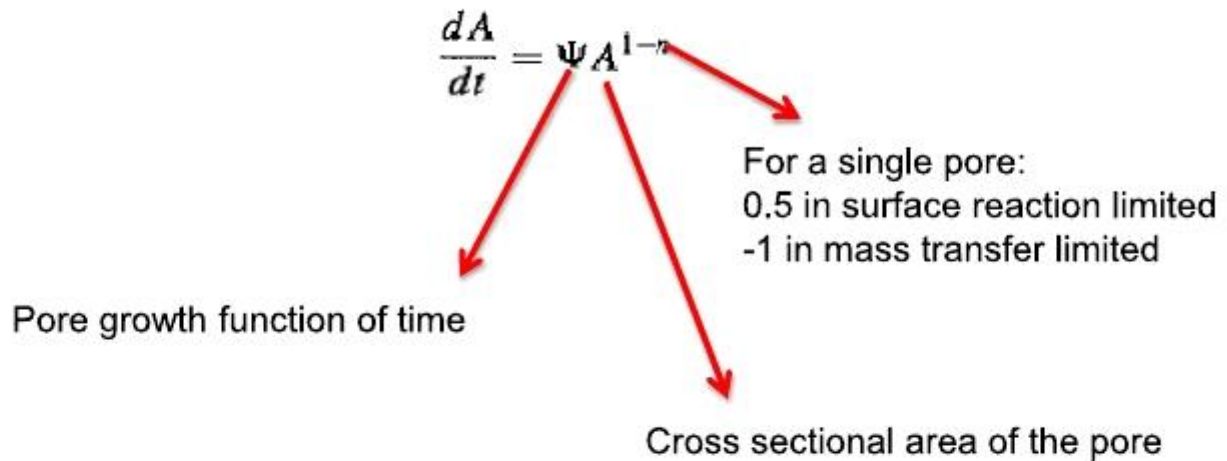
Limiting Factors for Wormhole Growth

- Mass transfer
- Reaction rate
- Fluid loss to small pores

- The structure of the wormhole depends on the relative rates of surface reaction, diffusion, and fluid loss which all of them depend on the overall convection rate of the acid.

Modes of Acid Attack

- Depend on the injection rate and the rock/acid interaction.
- For HCl/Limestone (very fast reaction) the attack modes are
  - Compact dissolution
  - Diffusion-limited wormholing
  - Fluid-loss limited wormholing
  - Uniform dissolution

Modes of Acid Attack
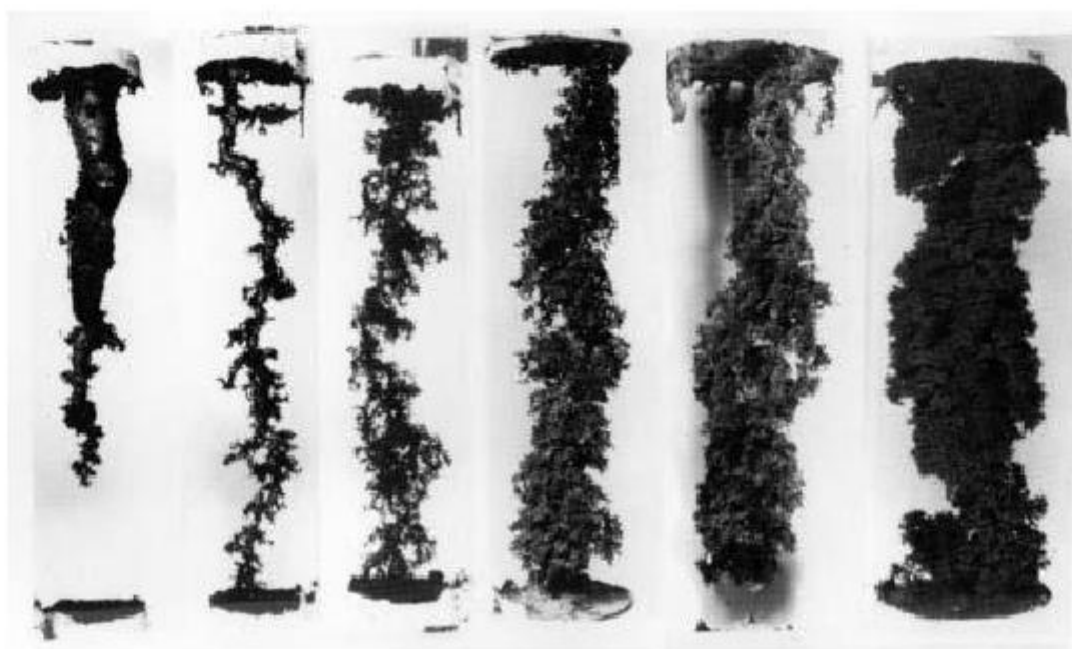
Injection rate →

Network Model to Show the Attack Modes

- Very low injection rate: the inlet face of the rock will be slowly consumed as acid diffuses to the surfaces.

Compact Dissolution
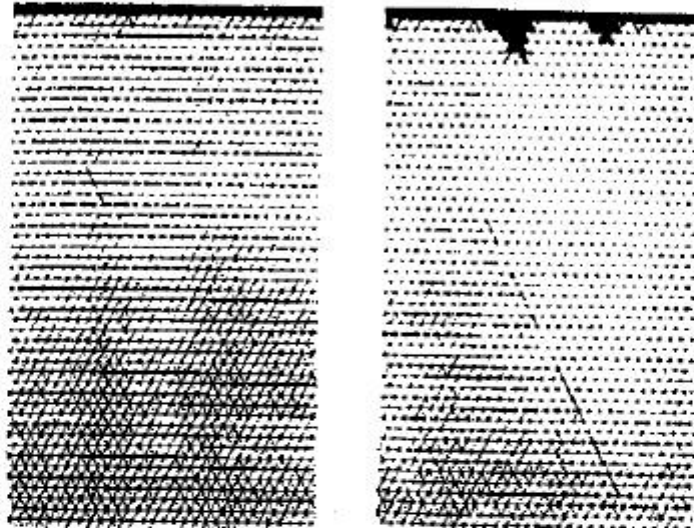
Network Model to Show the Attack Modes

- With increasing flow rate: a few dominant wormholes form and propagates into the porous medium. At low injection rates there will be little **branching.**

Diffusion-Limited Wormholing

(The volume of acid needed to propagate the wormhole a given distance decreases as injection rate increases.)
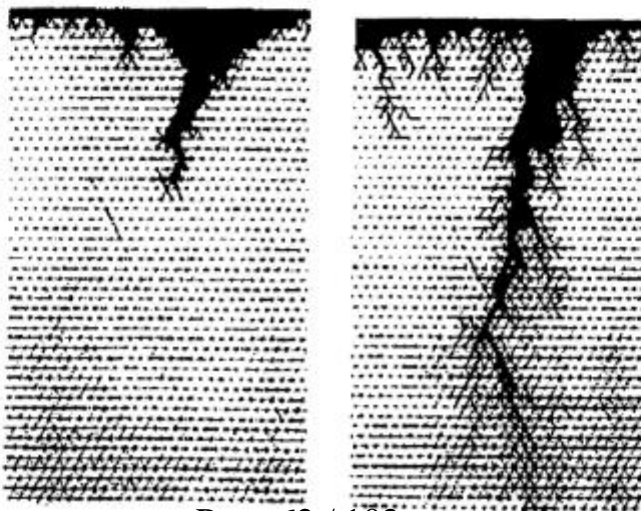
Network Model to Show the Attack Modes

- With increasing flow rate: More branches form, consuming significant amounts of acid and thus slowing the wormhole propagation rate.

Fluid Loss Limited Wormholing

(The acidizing efficiency decreases as injection rate increases.)
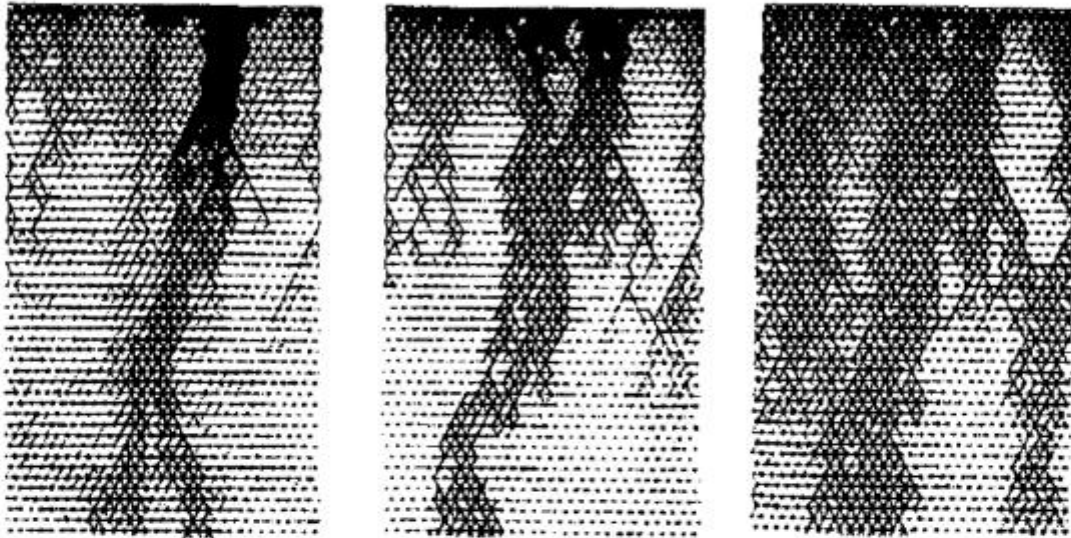
Network Model to Show the Attack Modes

- At very high injection rates: the mass transfer of acid is so rapid that the overall reaction rate becomes surface reaction rate limited.

Uniform Dissolution

(Never occurs to avoid fracturing)

$q = 0.04$ cm³/min	$q = 0.11$ cm³/min	$q = 0.3$ cm³/min	$q = 1.05$ cm³/min	$q = 10$ cm³/min	$q = 60$ cm³/min
$Da = 2.8$	$Da = 1.4$	$Da = 0.67$	$Da = 0.29$	$Da = 0.066$	$Da = 0.020$
$PV_{inj} = 43.1$	$PV_{inj} = 10.0$	$PV_{BT} = 3.3$	$PV_{BT} = 0.8$	$PV_{BT} = 2.1$	$PV_{BT} = 6.7$

Summary

OPTIMUM
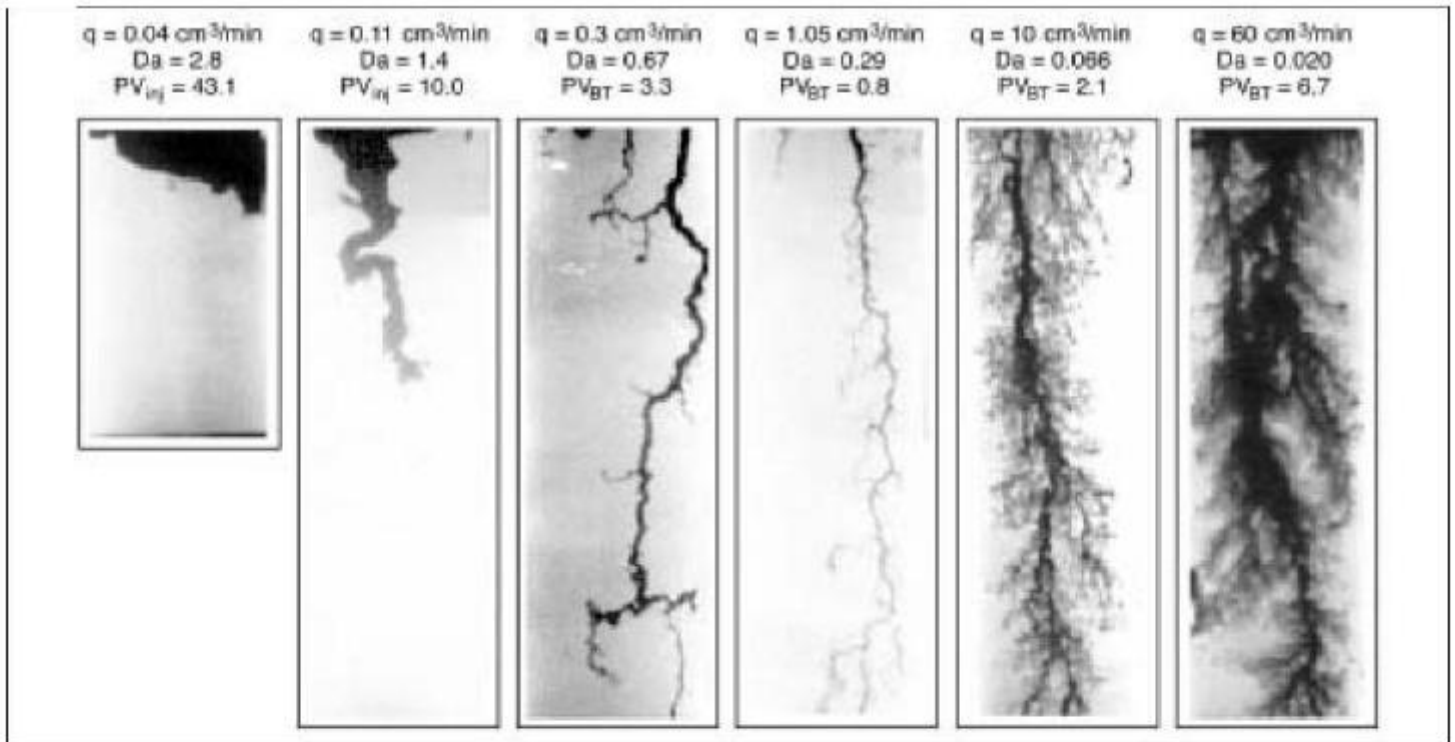
Mode 2: Propagation of wormhole increases

Mode 3: Propagation of wormhole Decreases due to fluid loss

Injection rate
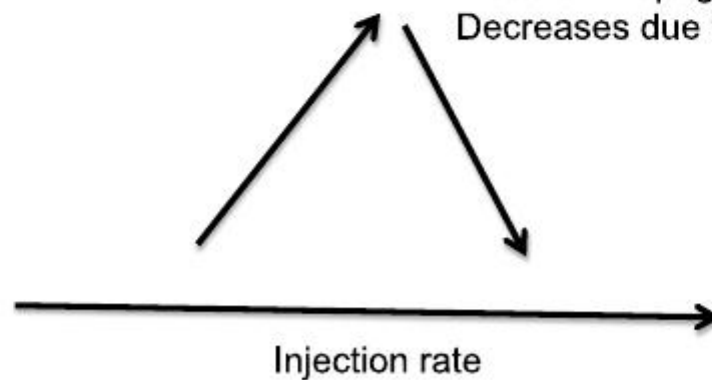
Core Flood (Limestone/HCl)
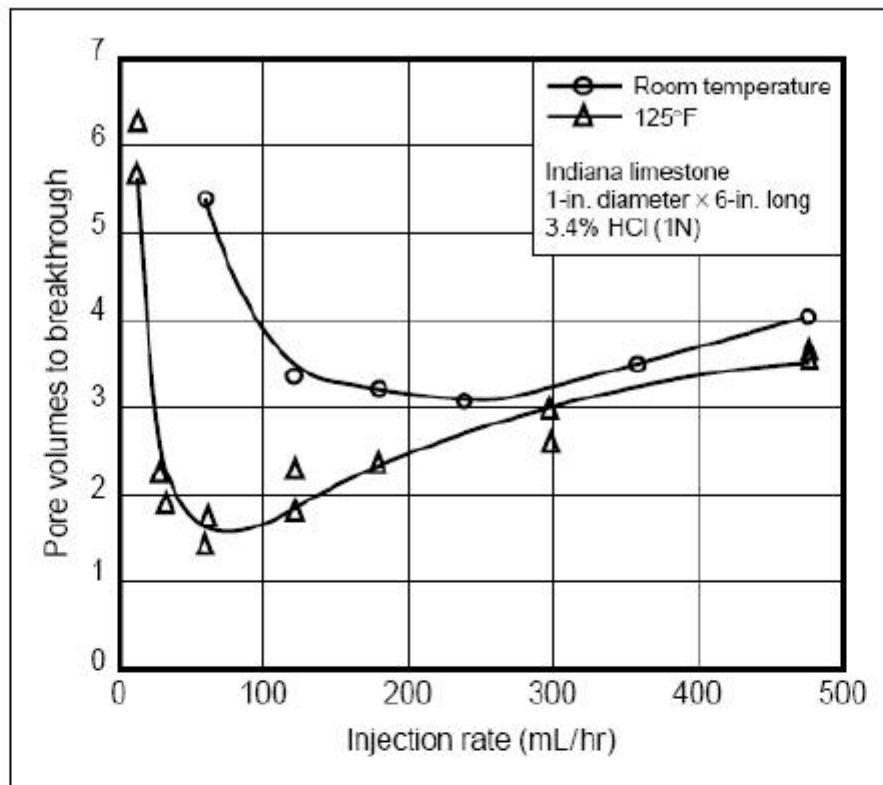
Core Flood (Dolomite/HCl)
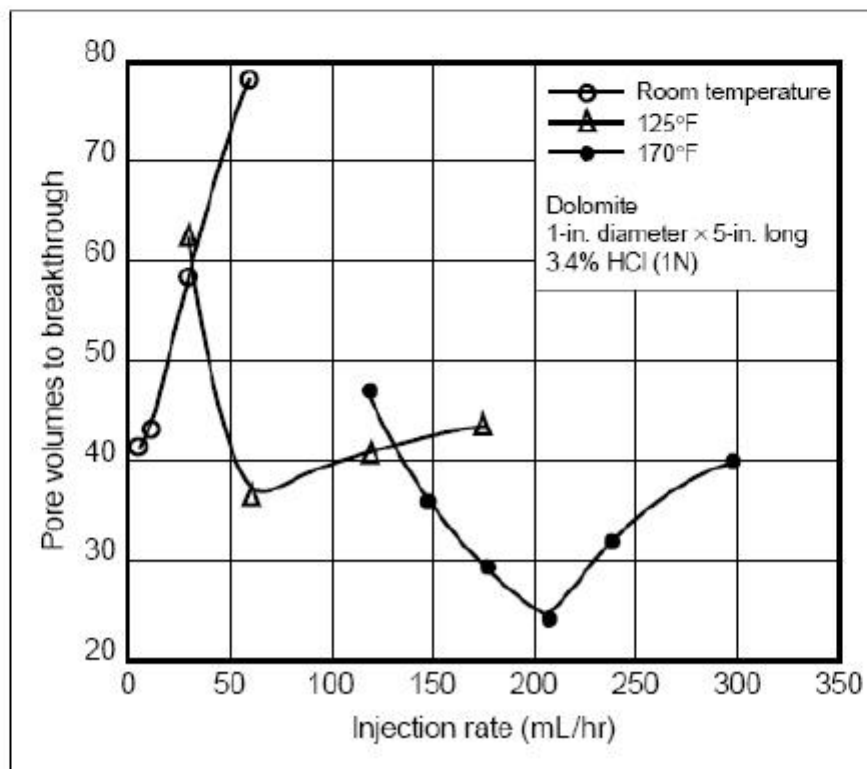
Different Acids
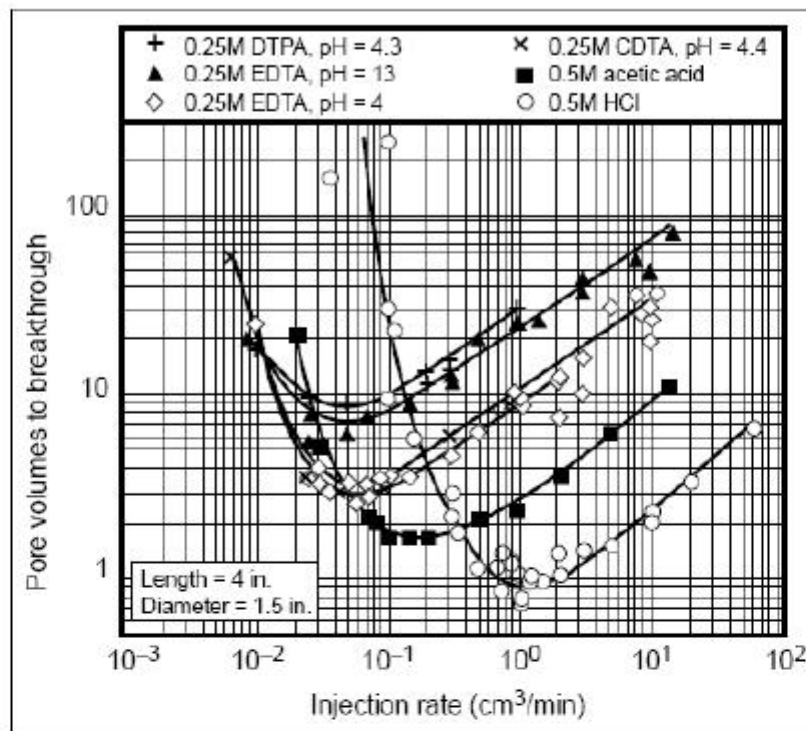
Wormholing Process Models

- Mechanistic model of a collection of wormholes
- Network model
- Stochastic model
- Volumetric model (simple empirical model)

Mechanistic Model

Total injection rate, q_T

Injection pressure, p_{inj}

Wormhole

Wormhole radius, r_{wh}

Flow at the tip, q_e

Fluid loss, q_L

Injection rate at core face, q_c

Length to tip, L_e
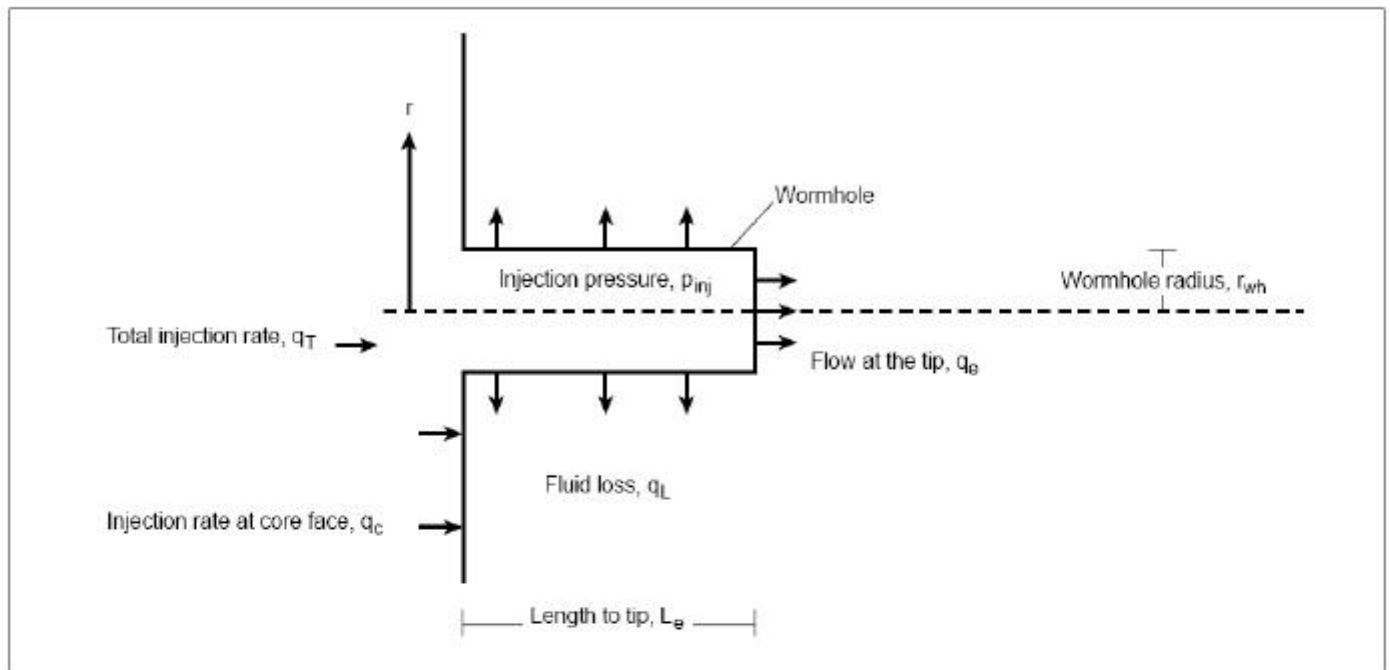
Mechanistic Model

- For high reaction rate, all of the acid transported to the end of the wormhole will be spent dissolving rock and extending the wormhole.

- The wormhole velocity

$$\frac{dL}{dt} = \frac{u_{end} C_{end} \rho_{acid} \beta_{100}}{(1 - \phi)\rho_{rock}}$$

where u_{end} and C_{end} are the flux and acid concentration (mass fraction) at the end of the wormhole. This can also be written in terms of the acid capacity number as

$$\frac{dL}{dt} = \left(\frac{u_{end}}{\phi}\right)\left(\frac{C_{end}}{C_0}\right) N_{Ac}$$

Stochastic Model

Daccord et al. found

$$r_{wh} = \left[\frac{bN_{Ac}V}{\pi h\phi} D^{-2/3} \left(\frac{q}{h}\right)^{-1/3} \right]^{1/d_f}$$

where r_{wh} is the radius of wormhole penetration, b is a constant, and d_f is the fractal dimension, found to be equal to about 1.6. Again substituting qt for V and differentiating with respect to time yields

$$\frac{dr_{wh}}{dt} = \frac{1}{d_f} \left(\frac{bN_{Ac}D^{-2/3}}{\pi\phi} \right)^{(1/d_f)} \left(\frac{q}{h}\right)^{(2/3d_f)} t^{(1/d_f - 1)}$$

This predicts that the wormhole velocity in radial flow increases with injection rate to the 0.4 power and decreases with time. Daccord et al. report the constant b to be 1.5×10^{-5} in SI units for their experiments in small radial core floods with water and plaster. It is likely that b is smaller for field systems.

Acid Volume (Method 1) Summary

$$V_h = \frac{\pi\phi D^{2/3} q_h^{1/3} r_{wh}^{d_f}}{bN_{Ac}}$$

where

V_h = required acid volume per unit thickness of formation, m^3/m

ϕ = porosity, fraction

D = molecular diffusion coefficient, m^2/s

q_h = injection rate per unit thickness of formation, $m^3/sec\text{-}m$

r_{wh} = desired radius of wormhole penetration, m

d_f = 1.6, fractal dimension

b = 105×10^{-5} in SI units

N_{Ac} = acid capillary number, dimensionless,

where the acid capillary number is defined as

$$N_{Ac} = \frac{\phi\beta\gamma_a}{(1-\phi)\gamma_m},$$

γ_a = acid specific gravity, water = 1.0

γ_m = mineral specific gravity, water = 1.0.

Example

Radius of wormhole penetration with Daccord's model

Calculate the radius of penetration of wormholes after the injection of 50 gal/ft of 15 wt% HCl at a rate of 0.1 bpm/ft into a limestone formation with a porosity of 0.2 using Daccord's fractal model. The molecular diffusion coefficient is 10^{-9} m²/sec.

Empirical Model (Volumetric Model)

- Assumption: acid will dissolve a constant fraction of the rock penetrated.

$$r_{wh} = \sqrt{r_w^2 + \frac{N_{Ac} V}{\eta \pi \phi h}}$$

The wormholing efficiency, η, can be estimated from linear core flood data as being

$$\eta = N_{Ac} \dot{P} V_{bt}$$

- The efficiency is measured in linear core flooding, so using it for radial flow overestimate the radius of the penetration.

Acid Volume

- Choose acid volume – tough choice.
- Acid reactions are not predictable.
- The damage area to treat is not well defined.
- A volumetric estimate of acid volume using lab data suggests

$$V = 23.49\phi h(r_{wh}^2 - r_w^2)PV_{bt}$$

where PV_{bt} is the lab PV injected at

acid break through at the end of

a core. V is in gals.

Example

Volumetric model of wormhole propagation

The data in Fig. 15-4 show that about 2 pore volumes of 1 N (3.4 wt%) HCl are required for wormholes to break through in a linear core flood in limestone, while Fig. 15-5 shows about 25 pore volumes of the same acid are needed for breakthrough in dolomite. Calculate the wormhole penetration after the injection of 50 gal/ft of 3.4 wt% HCl into limestone and dolomite, assuming that a constant fraction of the rock is dissolved. In both cases, the porosity is 0.2 and the wellbore radius is 0.328 ft.

Example

Required acid volume

Calculate the volume (gal/ft) of 28% HCl needed to propagate wormholes 3 ft from a 0.328-ft-radius wellbore in a limestone formation with a porosity of 0.15, using both Daccord's model and the volumetric model. The injection rate is 0.1 bpm/ft, the diffusion coefficient is 10^{-9} m^2/sec, and the density of 28% HCl is 1.14 g/cm^3. In linear core floods, 1.5 pore volumes are needed for wormhole breakthrough at the end of the core.

Acid Volume

- Acidizing parameters include acid volume, injection rate, and injection pressure. The acid volume can be calculated with two methods:
  - (1) Daccord's wormhole propagation model
  - (2) the volumetric model
- **The former is optimistic, whereas the latter is more realistic**

Acid Volume

- The volumetric estimate is normally a minimum volume.
- Rules of thumb place the volumes at between 50 to 200 gals/ft.
- At BHT greater than 200 deg F or in heavily damaged zones, move toward to 200 gal/ft end.
- For shallow damage or perforation cleaning use the 50 gal/ft range.
- Logistics and cost may limit acid volume.

WELL PERFORMANCE EVALUATION OF STIMULATED WELLS

An effective way to evaluate stimulation or to compare different stimulation designs is by comparing net payout due to stimulation over time. If a particular stimulation design pays out the cost of stimulation and yields a net revenue of x dollars in five months (whereas an alternative design does it in 10 months), the first design undoubtedly is the most acceptable or sellable design. Fig. 5.1 is an example plot of net payout vs time.
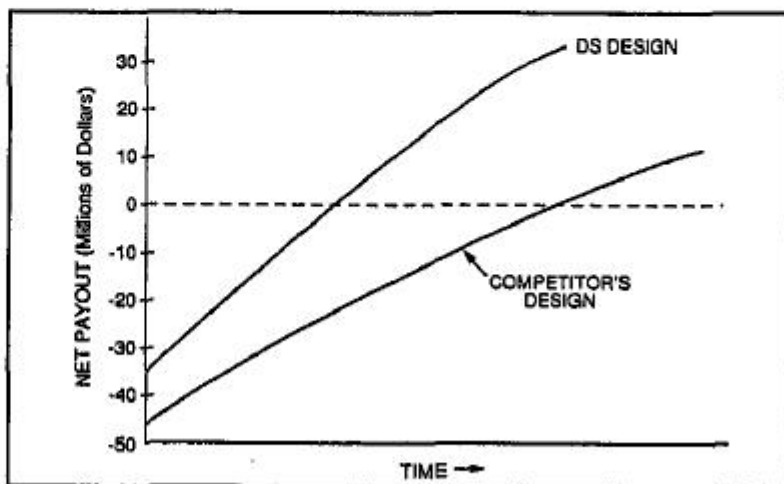
Fig. 5.1   Net Payout at any time = Extra revenue from oil or gas production due to stimulation at any time, t – cost of stimulation.

ARTIFICIAL LIFT

Artificial lift methods are used in oil wells that have adequate productivity but inadequate pressure to lift the oil to the surface. There are basically two methods of artificial lift.

.• Pumping

.• Gas Lift

Pumping Wells

Downhole pumps add pressure to the flowing system. As shown in Fig. 5.1, the dead oil column is stagnant and the hydrostatic pressure of the column overcomes the reservoir pressure stopping the

Fig. 5.2   Effect of subsurface pumps of well pressure profile.

inflow into the wellbore. Installation of a pump modifies the pressure profile by adding a fixed pressure gain between the suction and discharge sides of the pump. When properly designed, this pressure gain allows the fluid to flow to the surface at a fixed wellhead pressure. Pumps always operate with a positive suction pressure provided by a fluid column in the annulus above the pump level. This fluid level in the annulus can be monitored by an echometer. Before stimulating a pumping well, the fluid level in the annulus should be monitored to make the post-stimulation troubleshooting possible.

5-1

Diagnostic of potential stimulation needs in pumped oil wells –

In general, if the fluid level rises and the pump discharge rate falls, the problem is in the pump, (Case 1 of Fig. 5.3). It is not uncommon to encounter such problems after stimulation of a pumping well. In most of these cases, the old pump needs to be replaced or repaired.

The other common problem is when the flow rate falls and the fluid level stays the same or recedes. This is commonly due to a reservoir problem, such as depletion or skin buildup (Case 2 of Fig. 5.3).
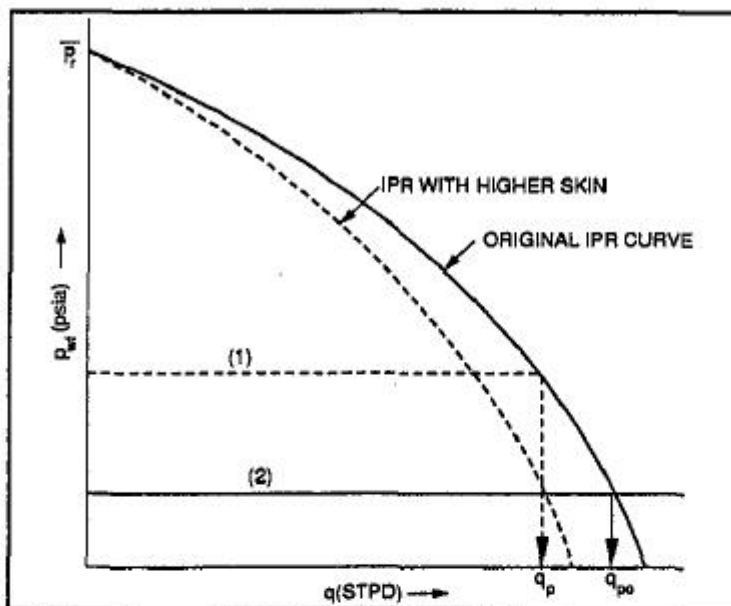
Fig. 5.3   *Showing potential problems in a pumping well through IPR curves.*

Note also that in a pumping well after a successful stimulation, the pumps may need to be redesigned for optimum flow. It is very possible that after a successful stimulation in a pumping well, the post stimulation production did not increase substantially due to existing pump limitations.

Gas Lift Wells

Gas lift is an artificial lift method where gas is injected to the liquid production string, normally through the tubing-casing annulus to aerate the liquid column, reducing the hydrostatic head of the liquid column. This reduces the bottomhole flowing pressure increasing production. The deeper the injection point, the longer the column of tubing fluid is aerated and the lower the bottomhole pressure. Thus, the objective of gas lift is to inject the optimum gas at the deepest possible point in the tubing. An optimum gas volume injection is very important because any higher volume leads to an excessive friction pressure loss in the tubing, thus overcoming the hydrostatic pressure gain. This situation results in an increase in the bottomhole flowing pressure, reducing production.

Figure 5.4 shows a typical gas injection sequence used to unload or kick off a gas lift well. Gas lift valves are used to close and open at fixed casing or tubing pressures. The objective of unloading is to start aerating a fluid column in smaller lengths beginning at the top and then close the top valve to aerate through the second valve, and so on until the injection valve is reached. This valve is set in such a way that it remains open all the time. This stepwise unloading is done to kick off a well with limited surface injection pressure.
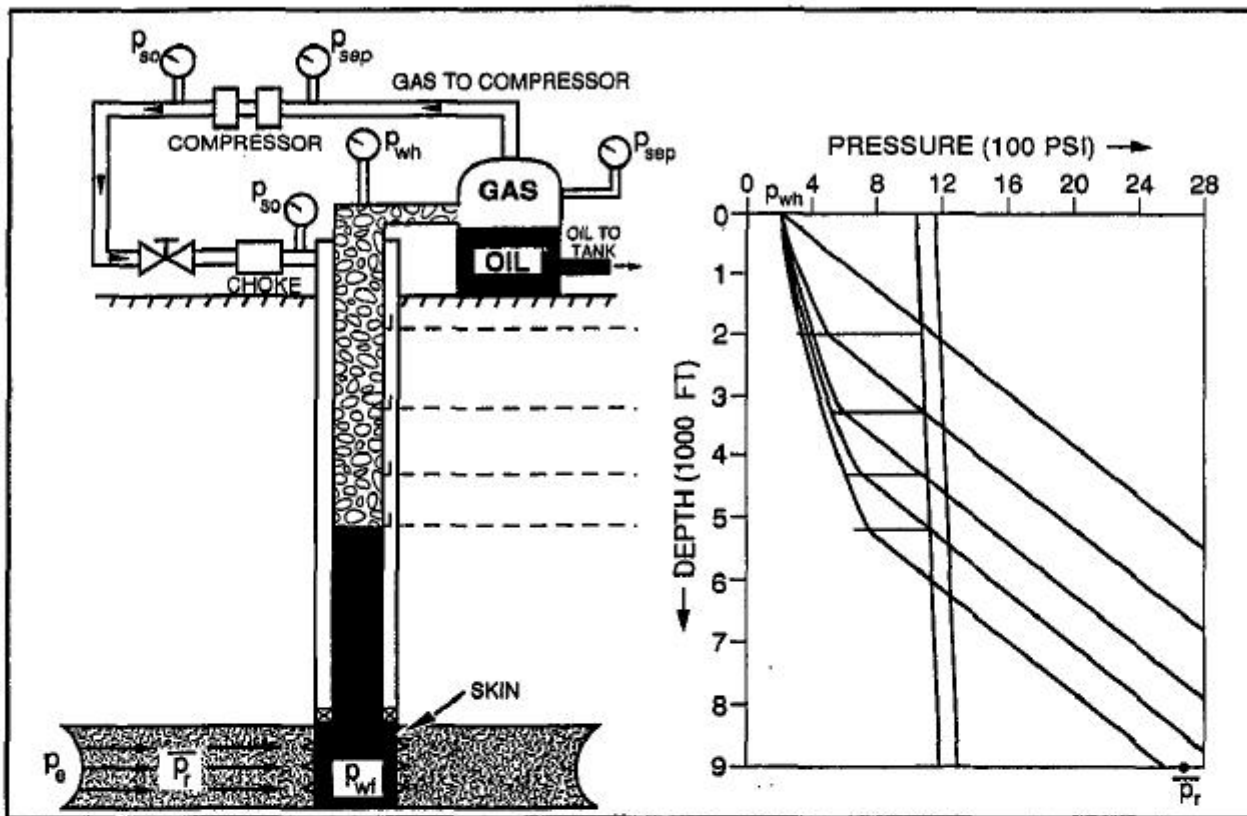
Fig. 5.4   Unloading wells with Gas Lift.

Effect of Stimulation of Gas Lift Wells

After stimulation with the improved IPR curve, a redesign of the gas lift system is normally required for optimized flow. This requires new setting of gas lift valves. It is possible that after stimulation a gas lift well loses production due to gas lift design problems. This section *is to caution DS* operations people against such gas lift system failures in a successfully stimulated well.

5-3

Example Problem 5.1 – Clay Consolidation (Clay Acid)

(Effect of moving damage away from the wellbore)
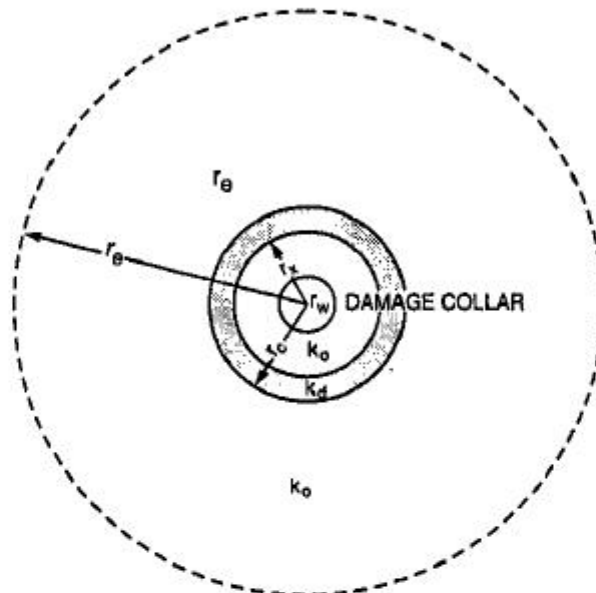
Fig. 5.5

$$\text{Average Permeability, } \overline{k} = \frac{\log\left(\dfrac{r_e}{r_w}\right)}{\dfrac{1}{k_o} \log \dfrac{r_x}{r_w} + \dfrac{1}{k_d} \log \dfrac{r_c}{r_x} + \dfrac{1}{k_o} \log \dfrac{r_e}{r_c}}$$

$$\text{Percentage of original Permeability } = \frac{\overline{k}}{k_o} \times 100$$

Given:

$$r_w = 0.365 \text{ ft}$$

$$\text{Formation Permeability, } k = 100 \text{ md}$$

$$\text{Spacing} = 160 \text{ acres}$$

(a) Calculate the percentage of original productivity due to 80% damage 1 ft deep around the wellbore.

(b) Calculate the percentage of original productivity due to an 80% damage collar, 1 ft wide and 4 ft from the wellbore.

Solution:

(a) $$k_{80\%} = \frac{\log\left(\frac{1,489}{0.365}\right)}{\frac{1}{20}\log\frac{1.365}{0.365} + \frac{1}{100}\log\frac{1,489}{1.365}}$$

$$= \frac{3.6106}{0.0286 + 0.0304}$$

$$= 61.2 \text{ md}$$

∴ Percentage of original productivity = 61%

(b) $$k_{80\%} = \frac{\log\left(\frac{1,489}{0.365}\right)}{\frac{1}{100}\log\frac{4.365}{0.365} + \frac{1}{20}\log\frac{5.365}{4.365} + \frac{1}{100}\log\frac{1,489}{5.365}}$$

$$= \frac{3.6106}{0.01078 + 0.00448 + 0.02443}$$

$$= 91 \text{ md}$$

∴ Percentage of original productivity = 91%

Example Problem 5.2 – Pre- and Post-acid Evaluation

Summary

An offshore Louisiana well was tested following its completion in the Pliocene formation. It produced 1,200 BPD at a wellhead pressure of 1,632 psig from a 71 ft. gravel-packed unconsolidated sandstone reservoir.

Analysis of the test data identified severe wellbore damage which was restricting production (Skin = 210). It also showed that the production rate could be increased to 6,850 BOPD at the same wellhead pressure should that damage be removed.

To treat the damage effectively, a clear understanding of its origin is needed. The analysis of the test data indicated inadequate perforations and a high probability of formation damage. This was confirmed by core analysis and production logs run after the test. An acid treatment was formulated and the post-acid test indicated a significant improvement in skin (Skin = 15). The production rate increased to 4,400 BOPD at a wellhead pressure of 2,060 psig.[1]

Pre-Acid Test Results

The main results are summarized on page 1 of the referred paper.[1] The test procedure and analysis plots are given in pages 2 through 5. The Model Verified Interpretation (page 3)

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[1] For more details refer to SPE 14820 presented at the 1986 SPE Symposium on Formation Damage Control, Lafayette, LA, February 26-27, 1986

indicates a high permeability homogeneous reservoir with wellbore storage and severe skin effect. The Nodal analysis (page 4) shows that the production rate is significantly restricted by the skin effect, and projects a rate increase of 5,650 BOPD if the wellbore damage is removed. Finally, the shot density sensitivity plot (page 5) suggests adequate perforations and the likelihood of formation damage. The interpretation charts and computation sheets are presented.

Production Logs Results

The production logging data indicate that all of the 40 ft. perforated zone is contributing to the flow rate except the bottom 5 to 6 ft. Since the permeability variation in the perforated interval is minimal and the flow profile appears nonuniform, it is assumed that formation damage has affected the producing zone unevenly.

Post-Acid Test Results

Significant improvement in the wellbore condition is noticed. The resulting increase in production rate matches the prediction of the Nodal analysis. The charts and computation sheets are presented in this section.

PRE-ACID ANALYSIS
NODAL ANALYSIS

Test Identification

Test Type .... SPRO
Test No. 1
Formation.............................. E–3 SAND
Test Interval (ft)......................... 11942–11982

Completion Configuration

Total Depth (MD/TVD) (ft)........... 11,920/10,800
Casing/Liner ID (in.) 6.094
Hole Size (in.)...............................8.5
Perforated Interval (ft) 40
Shot Density (shots/ft).................. 12
Perforation Diameter (in.) 0.610
Net pay (ft)................................... 71

Interpretation Results

Model of Behavior........................ Homogeneous
Fluid Type used for Analysis........ Liquid
Reservoir Pressure (psi)................ 5585
Transmissibility (md-ft/cp)........... 53390
Effective Permeability (md)...........526.0
Skin Factor...................................210.0

Test String Configuration

Tubing Vertical Multiphase
Flow ....Hagedorn-Brown
Tubing Length (ft)/ID (in.)........... 11,830/2.992
Packer Depth (ft) 11,826
Gauge Depth (ft)/Type................. 11,920/DPTT
Tubing Absolute Roughness (ft) .. 5.0E–05

Rock/Fluid/Wellbore Properties

Oil Density (° API).........................29.5
Gas gravity....................................0.600
GOR (scf/STB)............................. 628
Water Cut (%)............................... 0
Viscosity (cp)................................0.70
Total Compressibility (1/psi)........ 9.00E–06
Porosity (%) 28
Reservoir Temperature (°F).......... 218
Form. Vol. Factor (bbl/STB).........1.37
Bubble Point Pressure, psi 5120
Wellhead Pressure (psig).............. 1632
Wellhead Temp. (°F)....................100.0
Production Time (days).................3.0

MAXIMUM PRODUCTION RATE DURING TEST: 1,200 BPD

5-6

Test Objectives

The objectives of this test were to evaluate the completion efficiency and estimate the production potential of the well.

Comments

The test procedure and measurements are summarized on the following pages. The system behaved as a well in a homogeneous reservoir with wellbore storage and skin. The well and reservoir parameters listed above reveal a high permeability formation and a severely damaged wellbore. Removing this damage would result in increasing the production rate to 6,850 BOPD at the same wellhead pressure of 1,632 psig, without jeopardizing the integrity of the gravel pack. The shot density sensitivity plot suggests adequate perforations and high formation damage. This could be confirmed by production logs and core analysis. Acid treatment is recommended for removing the wellbore damage and increasing the production. Note that the skin due to partial penetration cannot be eliminated by acidizing – consequently the ideal production rate may not be achieved.

PRE-ACID TEST COMPUTATION SHEET

1. **LOG-LOG ANALYSIS**

    1.1 Match Parameters

Model:	Homogeneous, WBS & S	$C_D e^{2s}$	$= 1.0E185$
Pressure Match:		$P_D/\Delta P$	$= 0.23$
Time Match:		$(T_D/C_D)/\Delta t$	$= 1,700$

    1.2 Reservoir Parameter Calculations

    $$kh = 141.2\, Q_o\, \beta_o\, \mu_o \left(\frac{P_D}{\Delta P}\right)_{match} = 37{,}373.4 \text{ md-ft}$$

    $$C = \left(\frac{kh}{3{,}389\,\mu_o}\right)\left[\frac{\Delta t}{\left(\frac{T_D}{C_D}\right)}\right]_{match} = 0.0093 \text{ bbl/psi}$$

    $$C_D = \frac{0.8936\, C}{\phi\, C_t\, h\, r_w^2} = 370.7$$

    $$S = \frac{1}{2}\ln\left(\frac{C_D e^{2s}}{C_D}\right) = 210$$

5-7

2. GENERALIZED HORNER ANALYSIS

2.1 Straight Line Parameters

Superposition slope:	m'	=	4.1112 E-03
P (intercept):	P^*	=	5,585 psia
Pressure at one hour:	P (1 hr)	=	5,575 psia
Pressure at time zero:	P (0)	=	4,622 psia

2.2 Reservoir Parameter Calculations

$$kh = \frac{162.6\, B_o\, \mu_o}{m'} = 37,929 \text{ md-ft}$$

$$S = 1.151\left\{ \left(\frac{P(1\,hr) - P(O)}{m'\, Q_o} \right) - \log\left(\frac{k}{\phi\, \mu_o\, C_t\, r_w^2} \right) + 3.23 \right\} = 210$$

Nomenclature

k	=	permeability, md
h	=	formation height, ft
C	=	wellbore storage constant, bbl/psi
E	=	scientific notation
Q_o	=	oil flow rate BPD
P_D	=	dimensionless pressure
ΔP	=	pressure change, psi
T_D	=	dimensionless time
C_D	=	dimensionless wellbore storage constant
Δt	=	time change, hr
B_o	=	oil formation volume factor, bbl/STB
μ_o	=	oil viscosity, cp
ϕ	=	formation porosity

Fig. 5.6   Pressure /Flowrate History

SEQUENCE OF EVENTS

EVENT NO.	DATE	TIME (HR:MIN)	DESCRIPTION	ELAPSED TIME (HR:MIN)	BHP (PSIA)	WHP (PSIA)
1	23–APR	12:28	Run in Hole Flowing	0:48	1613.0	1636.0
2	23–APR	15:40	Start Monitoring Flow	4:00	4621.0	1649.0
3	23–APR	16:08	End Flow & Start Shut–In	4:28	4623.0	1648.0
4	23–APR	21:25	End Shut–In, POOH	9:45	5579.0	2434.0

SUMMARY OF FLOW PERIODS

PERIOD	DURATION (HR:MIN)	PRESSURE (PSIA)		FLOWRATE		CHOKE SIZE (INCHES)
		START	STOP	OIL (B/D)	GAS (MMSCF/D)	
#1, DD	3:40	1613.0	4623.0	1200.0	0.754	0/64
#2, BU	5:17	4623.0	5579.0	0	0	—
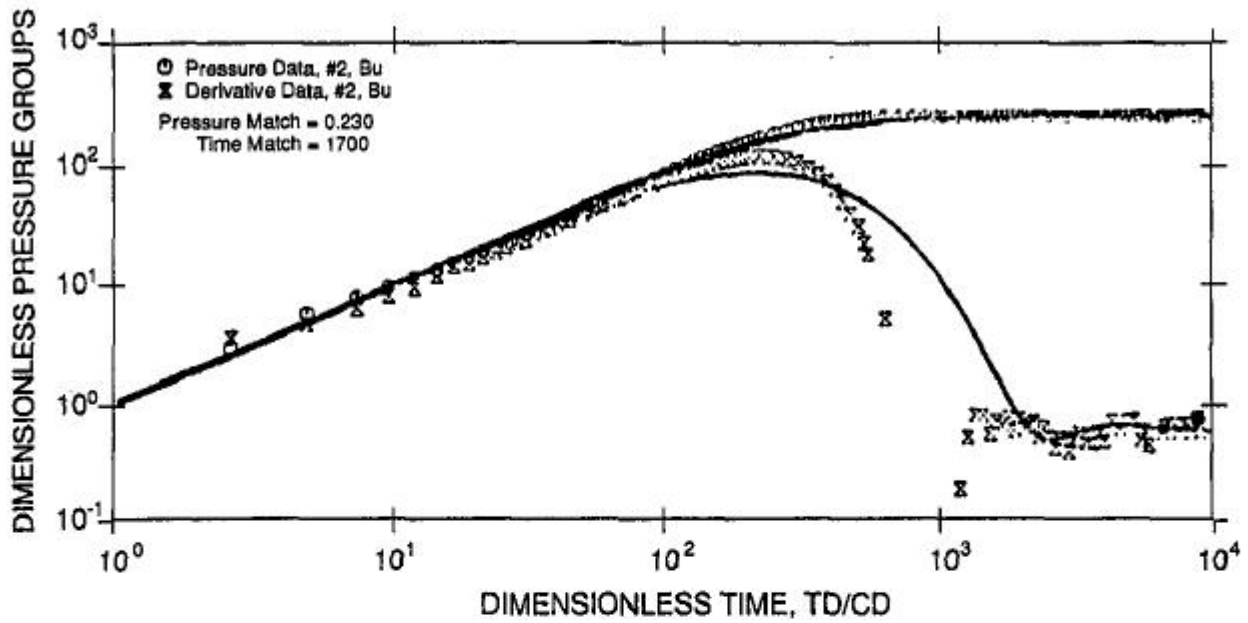
Fig. 5.7 Diagnostic Plot
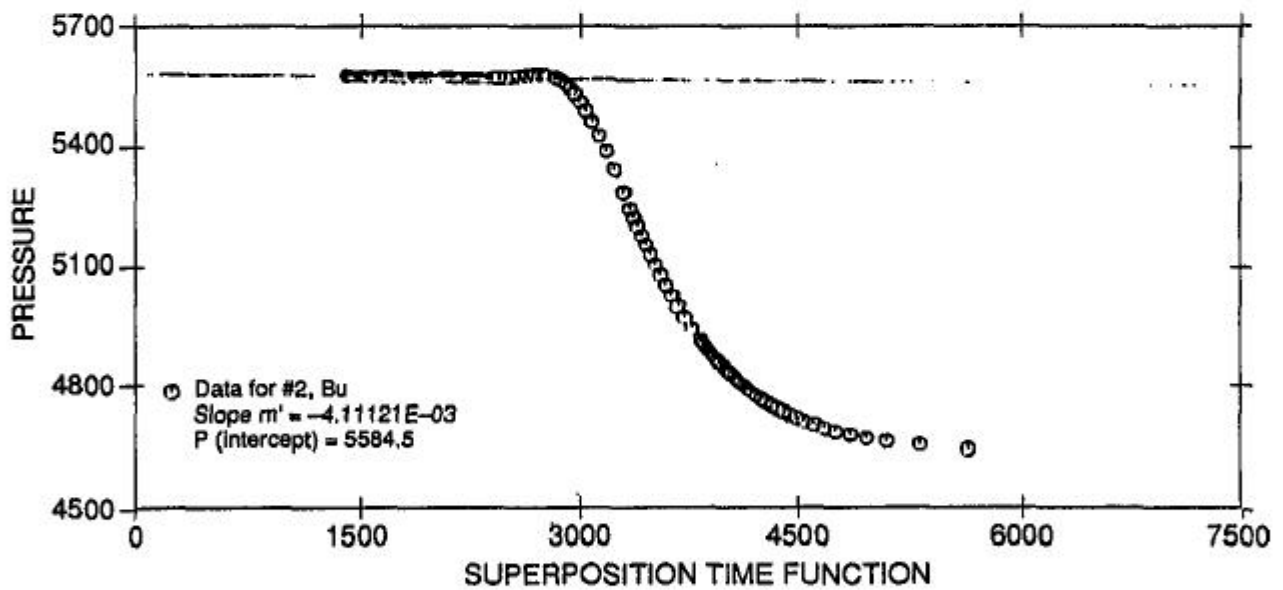
Fig. 5.8 Dimensionless Superposition

5-10

PRE–ACID TEST
Buildup Data

	Delta time (hours)	Bottomhole Pressure (psia)		Delta time (hours)	Bottomhole Pressure (psia)
1	0.00000E+00	4622.6	33	4.45000E-02	4879.3
2	1.50000E-03	4624.3	34	4.58333E-02	4886.8
3	2.83333E-03	4635.5	35	4.73333E-02	4894.3
4	4.16667E-03	4647.4	36	4.86667E-02	4901.8
5	5.66667E-03	4656.5	37	5.00000E-02	4909.1
6	7.00000E-03	4664.6	38	5.56667E-02	4938.5
7	8.33333E-03	4672.7	39	6.11667E-02	4967.3
8	9.83333E-03	4681.0	40	6.66667E-02	4995.6
9	1.11667E-02	4689.4	41	7.23334E-02	5023.2
10	1.25000E-02	4697.6	42	7.78333E-02	5050.2
11	1.40000E-02	4705.9	43	8.33334E-02	5076.6
12	1.53333E-02	4714.0	44	8.90000E-02	5102.4
13	1.66667E-02	4722.1	45	9.45000E-02	5127.6
14	1.81667E-02	4730.3	46	0.10000	5152.0
15	1.95000E-02	4738.4	47	0.10567	5175.7
16	2.08333E-02	4746.4	48	0.11117	5198.6
17	2.23333E-02	4754.5	49	0.11667	5220.8
18	2.36667E-02	4762.6	50	0.12233	5242.4
19	2.50000E-02	4770.6	51	0.13333	5283.0
20	2.65000E-02	4778.7	52	0.15000	5338.3
21	2.78333E-02	4786.6	53	0.16667	5386.6
22	2.91667E-02	4794.4	54	0.18333	5427.9
23	3.06667E-02	4802.4	55	0.20000	5462.8
24	3.20000E-02	4810.1	56	0.21667	5491.8
25	3.33333E-02	4817.9	57	0.23333	5515.2
26	3.48333E-02	4825.7	58	0.25000	5534.0
27	3.61667E-02	4833.4	59	0.26667	5548.4
28	3.75000E-02	4841.2	60	0.28333	5559.5
29	3.90000E-02	4848.9	61	0.30000	5567.5
30	4.03333E-02	4856.5	62	0.31667	5573.1
31	4.16667E-02	4864.1	63	0.32783	5576.0
32	4.31667E-02	4871.6	64	0.37783	5581.7

5-11

	Delta time (hours)	Bottomhole Pressure (psia)		Delta time (hours)	Bottomhole Pressure (psia)
65	0.42783	5582.3	99	2.2612	5576.8
66	0.47783	5580.8	100	2.3445	5576.9
67	0.52783	5578.2	101	2.5112	5577.0
68	0.57783	5576.1	102	2.6778	5577.2
69	0.62783	5574.0	103	2.8445	5577.4
70	0.69450	5573.8	104	3.0112	5577.5
71	0.74450	5574.1	105	3.1778	5577.7
72	0.79450	5574.4	106	3.3445	5577.8
73	0.84450	5574.5	107	3.4278	5577.9
74	0.89450	5574.6	108	3.8612	5577.9
75	0.94450	5574.9	109	3.8945	5578.0
76	0.99450	5574.9	110	3.9278	5578.2
77	1.0445	5575.1	111	4.0945	5578.3
78	1.0945	5575.2	112	4.2612	5578.5
79	1.1445	5575.3	113	4.4278	5578.5
80	1.1945	5575.5	114	4.5945	5578.6
81	1.2445	5575.5	115	4.7612	5578.7
82	1.2945	5575.7	116	4.9278	5578.7
83	1.3445	5575.7	117	5.0945	5578.9
84	1.3945	5575.9	118	5.1333	5578.9
85	1.4445	5575.9	119	5.1362	5578.9
86	1.4945	5576.0	120	5.1390	5579.0
87	1.5445	5576.1	121	5.1417	5579.0
88	1.5945	5576.1	122	5.1473	5578.9
89	1.6445	5576.2	123	5.1500	5579.0
90	1.6945	5576.2	124	5.1528	5579.0
91	1.7445	5576.2	125	5.1557	5579.0
92	1.7945	5576.4	126	5.1583	5579.0
93	1.8445	5576.4	127	5.1612	5579.0
94	1.8945	5576.5	128	5.1945	5578.9
95	1.9445	5576.4	129	5.2278	5578.9
96	1.9945	5576.5	130	5.2612	5579.0
97	2.0445	5576.6	131	5.2778	5579.0
98	2.0945	5576.7			

5-12

NODAL PLOT

Fig. 5.9 Production Potential Evaluation, Nodal Plot

RATE vs. WELLHEAD PRESSURE
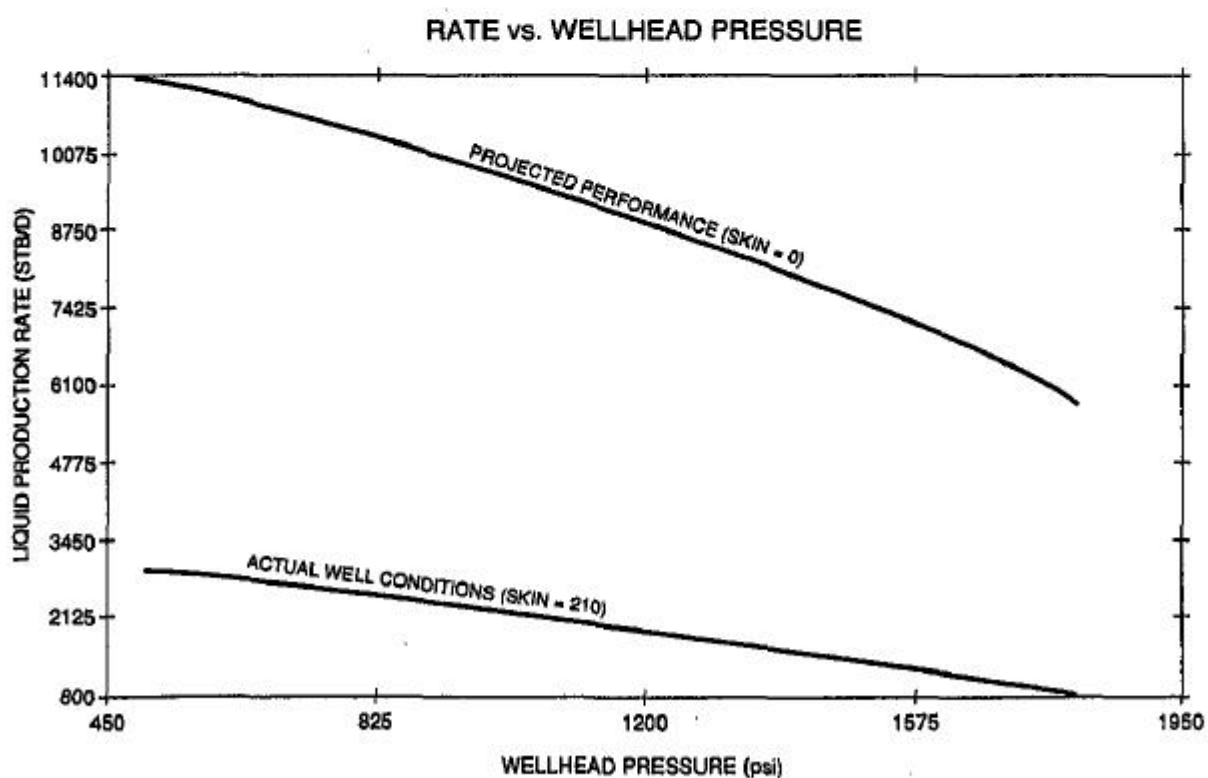
Fig. 5.10 Production Potential Evaluation, Rate vs. Wellhead Pressure.

5-13

WELL PERFORMANCE RATE vs. SHOT DENSITY
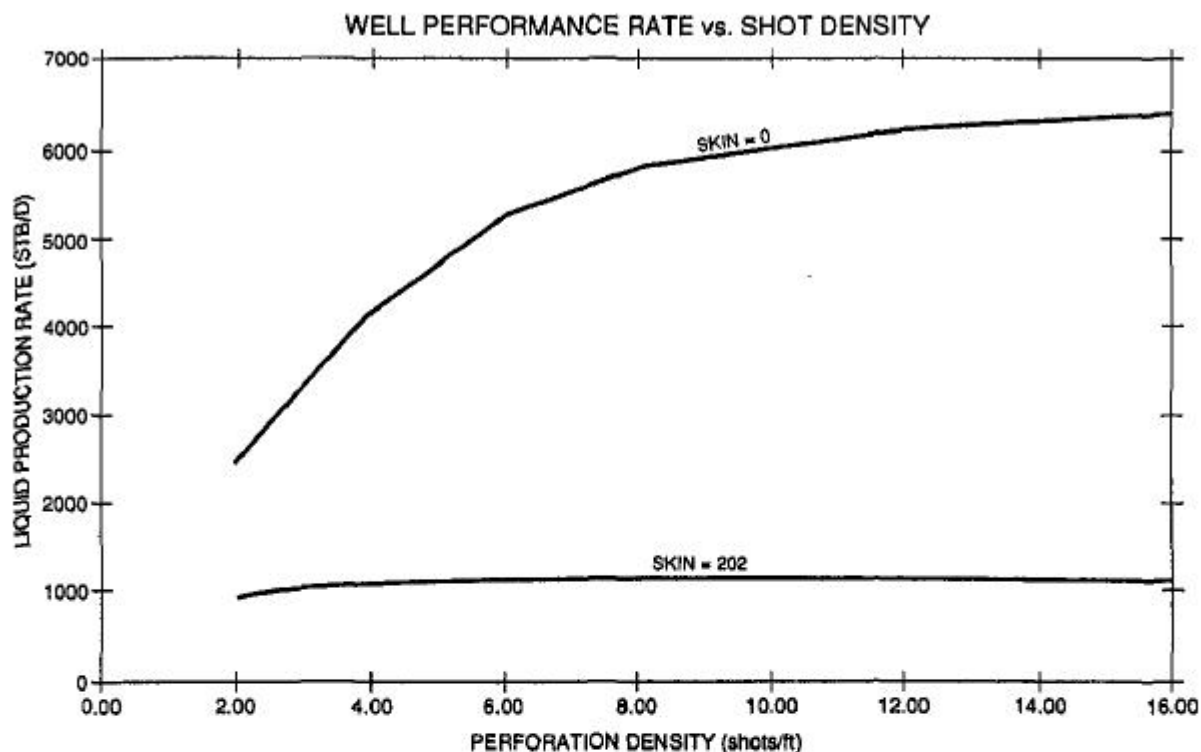
Fig. 5.11   *Production Potential Evaluation, Well Performance Rate vs. Shot Density*

POST-ACID ANALYSIS
NODAL ANALYSIS

Test Identification

Test Type	SPRO
Test No.	2
Formation	E–3 SAND
Test Interval (ft)	11942–11982

Completion Configuration

Total Depth (MD/TVD) (ft)	11,920/10,800
Casing/Liner I.D. (in)	6.094
Hole Size (in)	8.5
Perforated Interval (ft)	40
Shot Density (shots/ft)	12
Perforation Diameter (in)	0.610
Net pay (ft)	71

Interpretation Results

Model of Behavior	Homogeneous
Fluid Type used for Analysis	Liquid
Reservoir Pressure (psi)	5431
Transmissibility (md ft/cp)	53751
Effective Permeability (md)	530
Skin Factor	15

Test String Configuration

Tubing Length (ft)/I.D. (in)	11,830/2.992
Packer Depth (ft)	11,826
Gauge Depth (ft)/Type	11,920/DPTT
Downhole Valve (Y/N)/Type	N

Test Condition

Tubing/Wellhead Pressure (psi)	2,060
Separator Pressure (psi)	150
Wellhead Temperature (°F)	100.0

Rock/Fluid/Wellbore Properties

Oil Density (° API)	29.5
Gas gravity	0.600
GOR (scf/STB)	1,013
Water Cut (%)	0
Viscosity (cp)	0.70
Total Compressibility (1/psi)	9.00E–06
Porosity (%)	28
Reservoir Temperature (°F)	218
Form. Vol. Factor (bbl/STB)	1.37
Production Time (days)	2.5

MAXIMUM PRODUCTION RATE DURING TEST: 4,398 BPD

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Test Objectives

The objective of the test was to evaluate the effectiveness of the acid stimulation treatment.

Comment:

The test procedure and measurements are summarized on the next page. The acid treatment was effective in removing the formation damage. Analysis of the data revealed a significant improvement in the wellbore condition resulting in over a 3,000 BOPD increase in production at 428 psi higher wellhead pressure.

POST-ACID TEST COMPUTATION SHEET

1. LOG-LOG ANALYSIS

    1.1 Match Parameters

    Model: Homogeneous, WBS & S $C_D e^{2s}$ = 1.0E16
    Pressure Match: $P_D/\Delta P$ = 0.06318
    Time Match: $(T_D/C_D)/\Delta t$ = 1,300

    1.2 Reservoir Parameters Calculations

$$kh = 141.2\, Q_o\, \beta_o\, \mu_o \left(\frac{P_D}{\Delta P}\right)_{match} = 37,626 \text{ md-ft}$$

$$C = \left(\frac{kh}{3,389\, \mu_o}\right)\left[\frac{\Delta t}{\left[\frac{T_D}{C_D}\right]}\right]_{match} = 0.122 \text{ bbl/psi}$$

$$C_D = \frac{0.8936\, C}{\phi\, C_t\, h\, r_w^2} = 486$$

$$S = \frac{1}{2}\ln\left(\frac{C_D e^{2s}}{C_D}\right) = 15$$

2. GENERALIZED HORNER ANALYSIS

    2.1 Straight Line Parameters

    Superposition slope: m' = 4.14328 E-03
    P (intercept): P* = 5,430 psia
    Pressure at one hour: P (1 hr) = 5,401 psia

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Pressure at time zero: $\quad$ P (0) $\quad = \quad$ 5,041 psia

2.2 Reservoir Parameter Calculations

$$kh = \frac{162.6\, B_o\, \mu_o}{m'} = 37{,}635 \text{ md-ft}$$

$$S = 1.151\left\{\left(\frac{P\,(1\,hr) - P\,(O)}{m'\,Q_o}\right) - \log\left(\frac{k}{\phi\,\mu_o\,C_t\,r_w^2}\right) + 3.23\right\} = 15$$

Nomenclature

k $\quad = \quad$ permeability, md

h $\quad = \quad$ formation height, ft

C $\quad = \quad$ wellbore storage constant, bbl/psi

E $\quad = \quad$ scientific notation

Q_o $\quad = \quad$ oil flow rate, BPD

P_D $\quad = \quad$ dimensionless pressure

ΔP $\quad = \quad$ pressure change, psi

T_D $\quad = \quad$ dimensionless time

C_D $\quad = \quad$ dimensionless wellbore storage constant

Δt $\quad = \quad$ time change, hr

B_o $\quad = \quad$ oil formation volume factor, bbl/STB

μ_o $\quad = \quad$ oil viscosity, cp

ϕ $\quad = \quad$ formation porosity

PRESSURE/FLOWRATE HISTORY
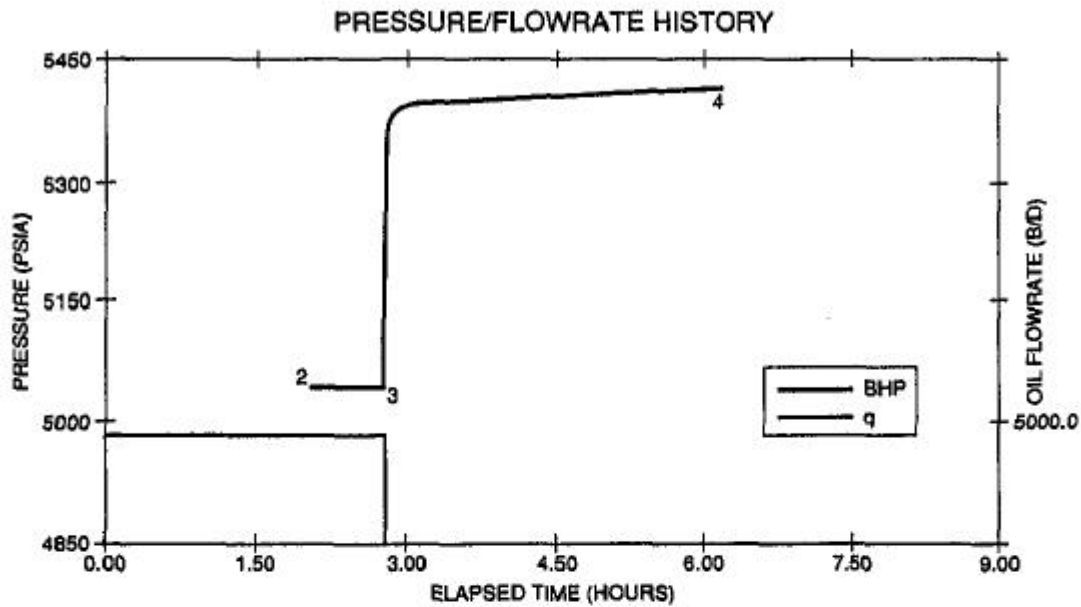
Fig. 5.12   Pressure/Flowrate History

SEQUENCE OF EVENTS

EVENT NO.	DATE	TIME (HR:MIN)	DESCRIPTION	ELAPSED TIME (HR:MIN)	BHP (PSIA)	WHP (PSIA)
1	16–JUN	11:05	Start Flowing Well	-50:40	N/A	N/A
2	17–JUN	11:05	Changed Choke	-26:40	N/A	N/A
3	18–JUN	11:02	Changed Choke	-2:43	N/A	N/A
4	18–JUN	13:45	Run In Hole Flowing	0:00	2083.0	2082.0
5	18–JUN	15:48	Start Monitoring Flow	2:03	5040.0	2077.0
6	18–JUN	16:30	End flow & Start Shut–In	2:45	5041.0	2075.0
7	18–JUN	19:58	End Shut–In, POOH	6:13	5411.0	2871.0

SUMMARY OF FLOW PERIODS

PERIOD	DURATION (HR:MIN)	PRESSURE (PSIA)		FLOWRATE		CHOKE SIZE (INCHES)
		START	STOP	OIL (B/D)	GAS (MMSCF/D)	
#1, DD	24:00	N/A	N/A	3565.0	N/A	N/A
#2, DD	23:57	N/A	N/A	4006.0	N/A	N/A
#3, DD	5:28	N/A	5041.0	4398.0	4.45	N/A
#4, BU	3:28	5041.0	5411.0	0	0	—

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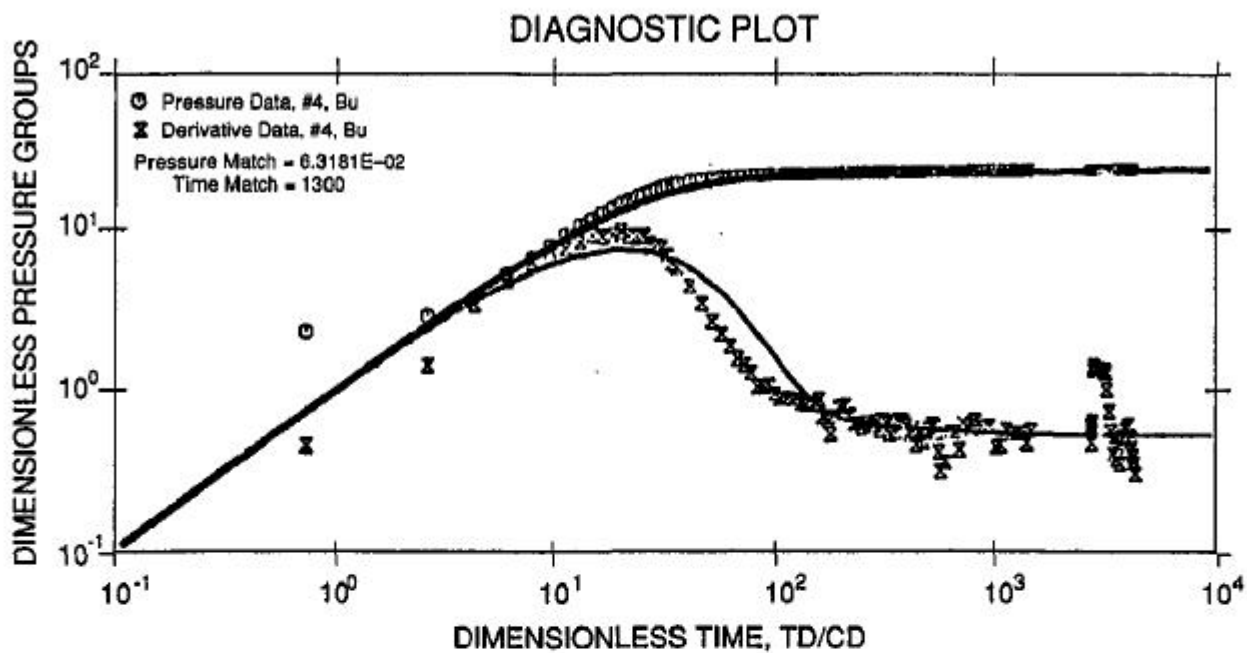
DIAGNOSTIC PLOT

Fig. 5.13   Post-Acid Test Validation, Diagnostic Plot

DIMENSIONLESS SUPERPOSITION

Fig. 5.14   Post-Acid Test Validation, Dimensionless Superposition

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POST–ACID TEST
Buildup Data

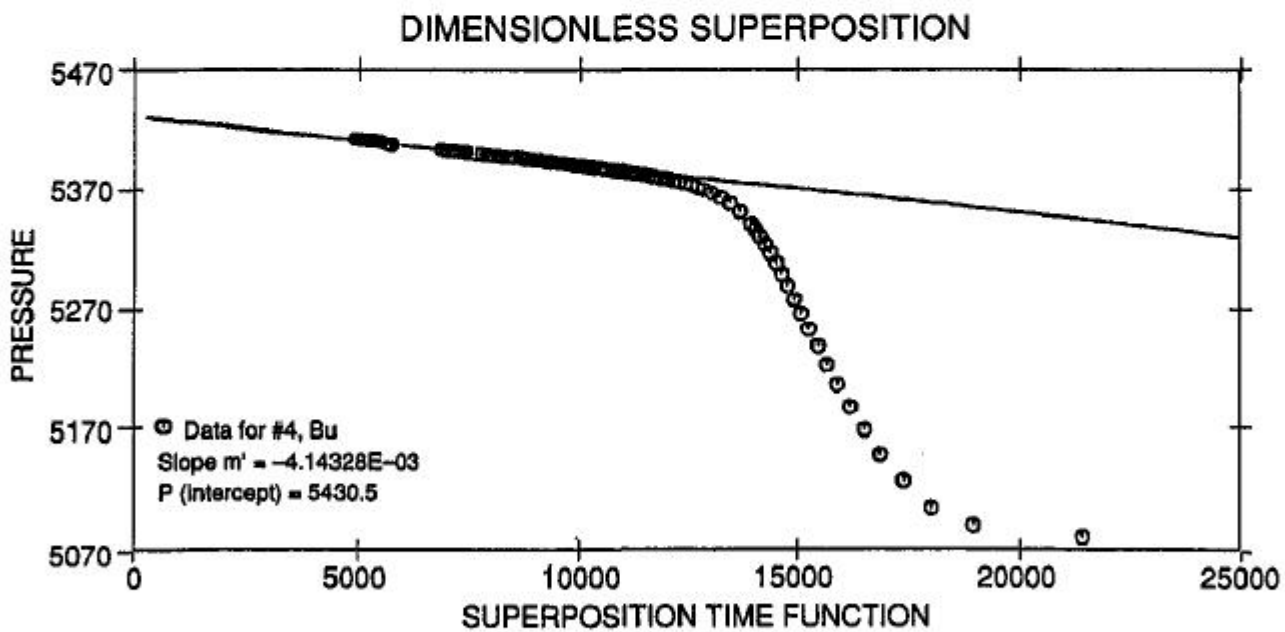|	Delta time (hours)	Bottomhole Pressure (psia)		Delta time (hours)	Bottomhole Pressure (psia)
1	0.00000E+00	5040.6	29	3.88334E-02	5327.7
2	1.33336E-03	5040.7	30	4.03333E-02	5333.3
3	2.83330E-03	5040.7	31	4.16667E-02	5338.1
4	4.16667E-03	5040.8	32	4.58333E-02	5348.8
5	5.50003E-03	5040.8	33	5.00000E-02	5356.2
6	6.99997E-03	5040.8	34	5.41667E-02	5361.1
7	8.33333E-03	5041.9	35	5.83333E-02	5364.7
8	9.66670E-03	5049.3	36	6.25000E-02	5367.5
9	1.11666E-02	5058.2	37	6.66667E-02	5369.7
10	1.25000E-02	5067.5	38	7.08333E-02	5371.4
11	1.38334E-02	5076.5	39	7.50000E-02	5372.9
12	1.53333E-02	5085.5	40	7.91667E-02	5374.1
13	1.66667E-02	5099.5	41	8.33333E-02	5375.0
14	1.80000E-02	5122.5	42	8.75000E-02	5376.0
15	1.95000E-02	5144.3	43	9.16667E-02	5376.8
16	2.08333E-02	5085.5	44	9.58333E-02	5165.2
17	2.21667E-02	5184.7	45	0.10000	5378.2
18	2.36666E-02	5203.2	46	0.10417	5378.8
19	2.50000E-02	5220.2	47	0.10833	5379.5
20	2.63334E-02	5236.1	48	0.11250	5380.1
21	2.78333E-02	5250.8	49	0.11667	5380.6
22	2.91667E-02	5264.0	50	0.12083	5381.1
23	3.05000E-02	5276.3	51	0.12500	5381.5
24	3.20000E-02	5287.4	52	0.12917	5382.0
25	3.33333E-02	5297.4	53	0.13333	5382.5
26	3.46667E-02	5306.4	54	0.13750	5382.9
27	3.61666E-02	5314.4	55	0.14167	5383.3
28	3.75000E-02	5321.5	56	0.14583	5383.8

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	Delta time (hours)	Bottomhole Pressure (psia)		Delta time (hours)	Bottomhole Pressure (psia)
57	0.15000	5383.9	88	0.40133	5393.6
58	0.15417	5384.2	89	0.40967	5393.8
59	0.15967	5384.6	90	0.41800	5393.9
60	0.16800	5385.2	91	0.42633	5394.2
61	0.17633	5385.9	92	0.43467	5394.3
62	0.18467	5386.3	93	0.44300	5394.5
63	0.19300	5386.9	94	0.45133	5394.8
64	0.20133	5387.3	95	0.45967	5394.8
65	0.20967	5387.6	96	0.48467	5394.9
66	0.21800	5388.0	97	0.50967	5395.4
67	0.22633	5388.4	98	0.53467	5395.5
68	0.23467	5388.8	99	0.55967	5395.9
69	0.24300	5389.0	100	0.58467	5396.4
70	0.25133	5389.4	101	0.60967	5396.5
71	0.25967	5389.8	102	0.63467	5397.2
72	0.26800	5390.0	103	0.65967	5397.4
73	0.27633	5390.4	104	0.70967	5398.0
74	0.28467	5390.6	105	0.75967	5398.7
75	0.29300	5390.8	106	0.80967	5399.3
76	0.30133	5391.1	107	0.85967	5399.5
77	0.30967	5391.4	108	0.90967	5400.0
78	0.31800	5391.8	109	0.95667	5400.5
79	0.32633	5391.9	110	1.0097	5401.0
80	0.33467	5392.2	111	1.0597	5401.2
81	0.34300	5392.4	112	1.1097	5401.6
82	0.35133	5392.5	113	1.1597	5402.0
83	0.35967	5392.8	114	2.1638	5406.1
84	0.36800	5392.9	115	2.1763	5406.3
85	0.37633	5393.2	116	2.1888	5406.2
86	0.38467	5393.2	117	2.2013	5406.3
87	0.39300	5393.5	118	2.2138	5406.3

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	Delta time (hours)	Bottomhole Pressure (psia)		Delta time (hours)	Bottomhole Pressure (psia)
119	2.2263	5406.4	132	2.9138	5409.8
120	2.2388	5406.4	133	2.9638	5410.2
121	2.3430	5406.8	134	30.138	5410.0
122	2.5055	5409.0	135	3.0638	5410.3
123	2.5097	5409.0	136	3.1138	5410.2
124	2.5138	5409.0	137	3.1638	5410.4
125	2.5638	5409.1	138	3.2138	5410.8
126	2.6138	5409.3	139	3.2638	5410.8
127	2.6638	5409.4	140	3.3138	5410.9
128	2.7138	5409.3	141	3.3638	5410.9
129	2.7638	5409.5	142.	3.4138	5411.1
130	2.8138	5409.9	143	3.4638	5411.0
131	2.8638	5409.8			

Fig. 5.15   Post-Acid Production Evaluation, Nodal Plot

5-21

RATE vs. WELLHEAD PRESSURE
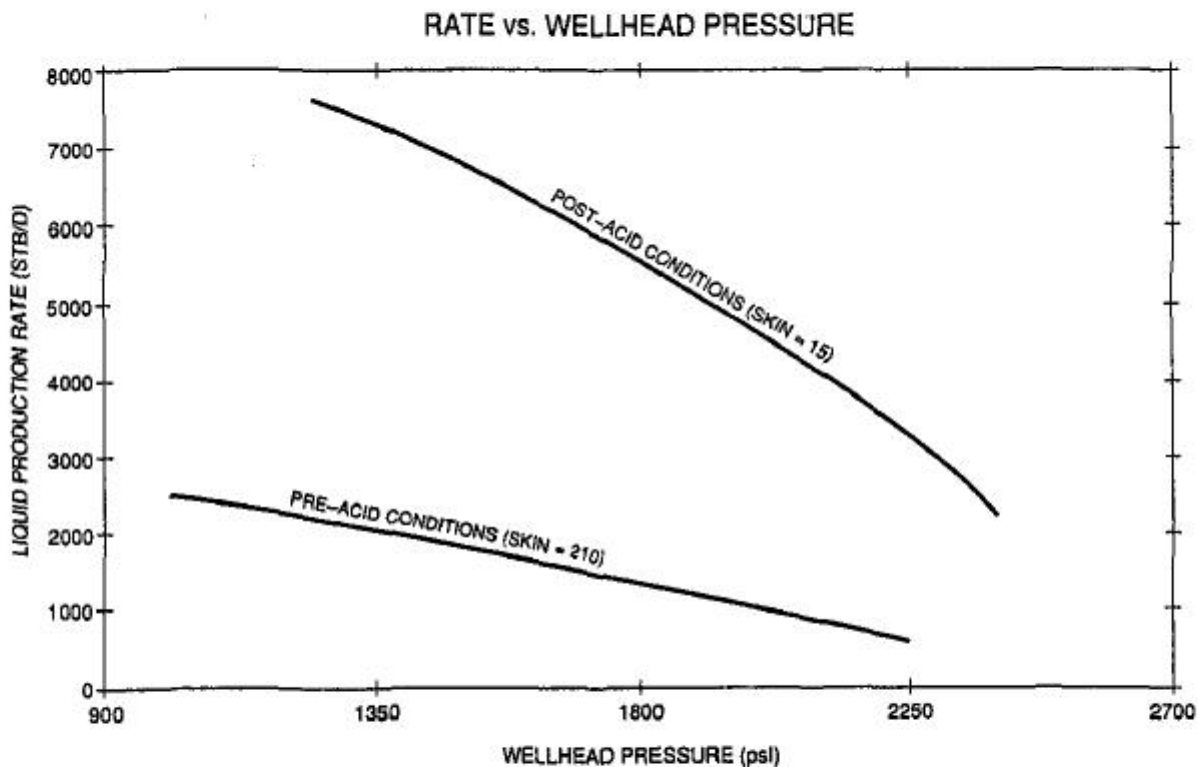

Fig. 5.16   Post-Acid Production Evaluation, Rate vs. Wellhead Pressure

Example Problem 5-3: Producing Well

Using tubing data from Example Problem 4-2 and reservoir parameters from Example Problem 2-3(b) (s = –5), calculate the natural production of the well.

k = 5md	$\bar{p}_r$ =2,500 psig
h = 20 ft	s = –5
μ_o = 1.1 cp	B_o = 1.2 RB/STB
Spacing = 80 acres	r_w = 0.365 ft

Solution:

$$\text{Drainage radius, } r_e = \sqrt{\frac{80 \times 43,560}{\pi}} = 1,053 \text{ ft}$$

$$\text{AOFP} = q = \frac{7.08 \times 10^{-3} \, kh \, \bar{p}_r}{\mu_o \, B_o \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s \right]}$$

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$$= \frac{7.08 \times 10^{-3} \times 5 \times 20 \times 2{,}500}{1.1 \times 1.2 \left[\ln\left(\frac{1{,}053}{0.365}\right) - 0.75 - 5 \right]}$$

$$= 604 \text{ STB/D}$$

From example 4-2, the following tubing intake pressures are calculated for different flow rates:

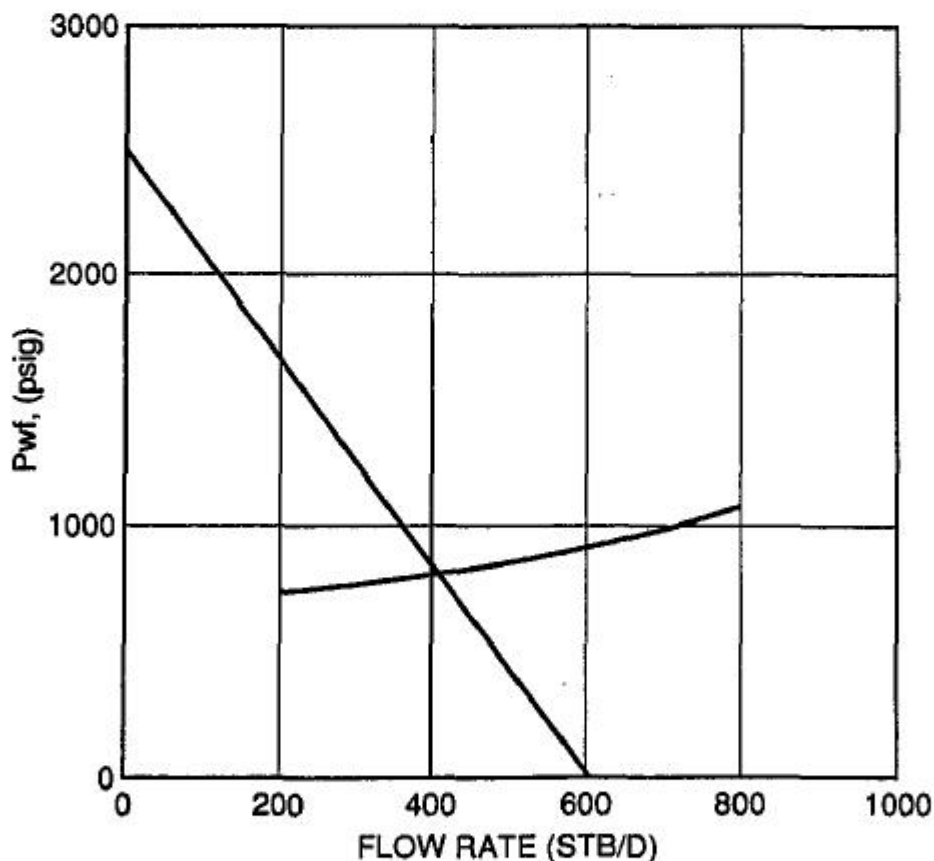| q (BPD)	p_{wf} (psig)
200	730
400	800
600	910
800	1,080

Fig. 5.17   *Example Problem 5.3. IPR and Tubing Intake Curve*

These values are plotted on the figure shown above. The intersection of the tubing intake curve and the IPR curve gives the natural production of the well, i.e., 410 STB/D.

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Example Problem 5-4

Solve Example Problem 5-3 for varying r_w, i.e., r_w = 100 ft, 200 ft, 400 ft, and 800 ft. Make a plot of q vs r_w. (Use a skin factor of +2.)

Solution:

The tubing intake curve is plotted as shown in Example Problem 5-3 with the following points:

q (BPD)	p_{wf} (psig)
200	730
400	800
600	910
800	1,080

Using data from Example Problem 5-3, the value of production rate q is calculated for different values of r_w and plotted:

(i) r_w = 100 ft

$$AOFP = q = \frac{7.08 \times 10^{-3} \, kh \, \bar{p}_r}{\mu_o \, B_o \left[\ln \left(\frac{r_e}{r_w} \right) - 0.75 + s \right]}$$

$$= \frac{7.08 \times 10^{-3} \times 5 \times 20 \times 2,500}{1.1 \times 1.2 \left[\ln \left(\frac{1,053}{100} \right) - 0.75 + 2 \right]}$$

$$= 372 \text{ STB/D}$$

Similarly, the flow rates at other values of r_w are calculated and plotted:

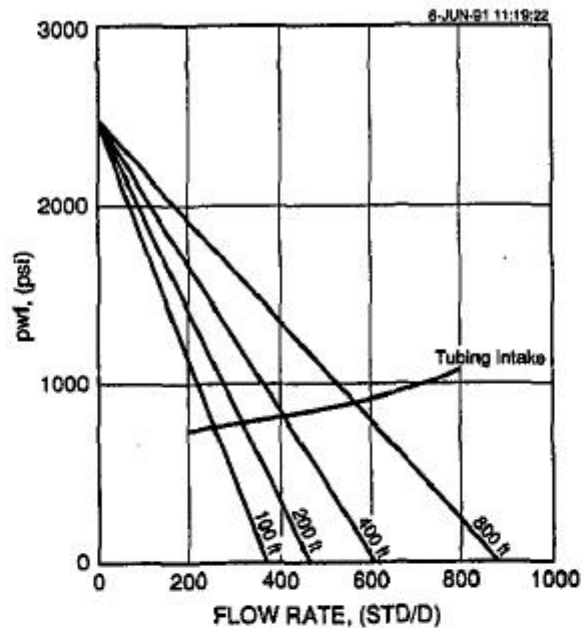| r_w (ft)	q (STB/D)
100	372
200	461
400	605
800	879

Fig. 5.18 Plot of tubing intake vs production rates for different r_w.

From the above plot, production rate is read-off at the intersection of the tubing intake curves and the IPR curves for the different values of effective wellbore radius. These are tabulated and plotted –

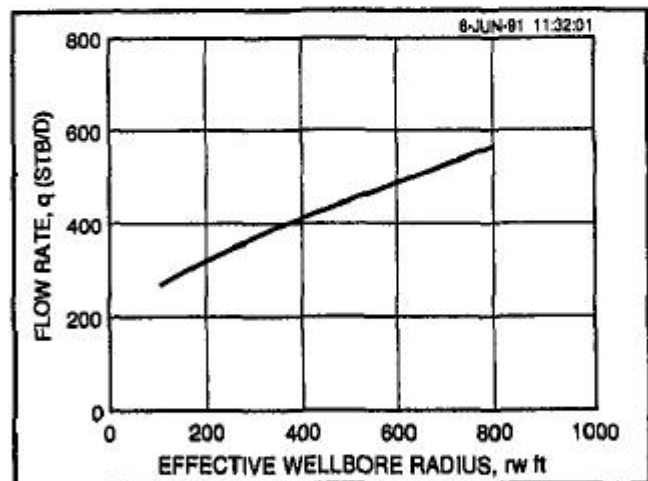| r_w (ft)	q (STB/D)
100	265
200	320
400	410
800	565

Fig. 5.19   Plot of flow rate vs effective wellbore radius.

Note: Hydraulically induced fractures increase the effective wellbore radius (Prats, 1961 – Appendix F).

Example Problem 5-5

Using the data from Example Problem 5-3 (tubing intake and IPR) and Example Problem 3-1 (Table 3-2), do a shot density sensitivity analysis.

Solution

Calculate and plot the response curve from Fig. 5.17 (Example Problem 5-3) as follows:

Response Curve Calculation

q (STB/D)	Δp
200	938
250	713
300	488
350	244
400	40
410	0

Using data from Table 3.2, plot the pressure drop vs flow rate for different shot densities on the same plot as the response curve.

The intersection of the response curve with the shot density curves gives the production rate for different shot densities.
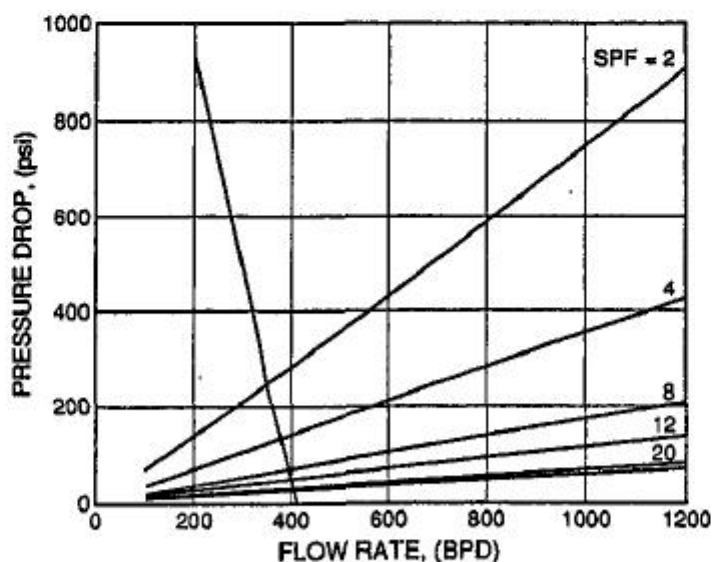

Fig. 5.20   Plot of flow rate vs pressure drop for varying shot densities.

These values are read off and tabulated as

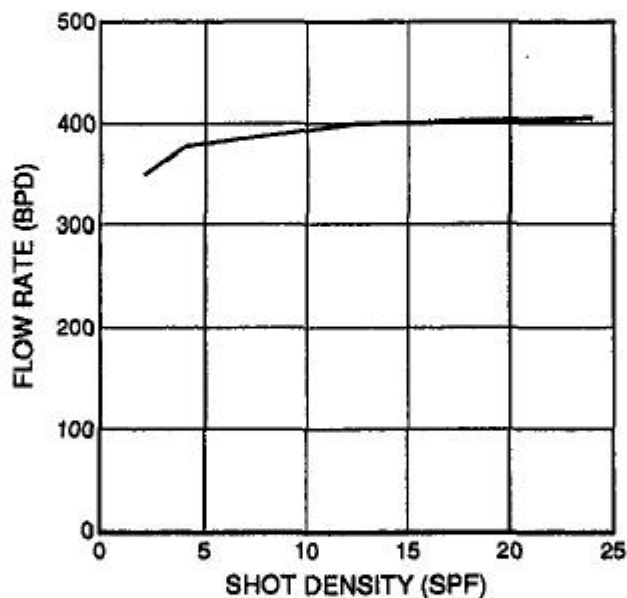| Shot Density (SPF)	Flow Rate (BPD)
2	350
4	378
8	390
12	400
20	405
24	408

These values are then plotted as shown here.

Fig. 5.21   Plot of shot density vs flow rate.

Exercises

1. For the following well data, calculate the absolute open flow potential of the well.

k_o	=	30 md	P_r	=	3,000 psia
h	=	40 ft	GOR	=	300 scf/STB
API	=	30	h_p	=	10 ft

    Reservoir Temperature = 200°F

γ_g	=	0.7	160 acre spacing	
(Produces all oil)			Drilled hole size	= 12-1/4 in.

    Casing size = 7 in.

2. Calculate ln (r_e/r_w) for $r_w = 7$ in. and for drainage areas of 20, 40, 80, 160 and 320 acres.

   Hint: make a table.

Drainage Acres	r_e	r_w	ln (r_e / r_w)
20			
40			
80			
160			
320			

3. Draw the IPR for a well with the following data –

k	=	50 md	Depth	=	5,000 ft
h	=	100 ft			
P_r	=	2,000 psia	(Producing all oil)		

   Determine the absolute open flow potential and an estimated production if you designed the tubular.

4. Draw the IPR in Problem #1 for skin of –5, 0, +5.

5. Using Vogel's IPR relationship, construct an IPR for the following cases –

   (a) P_r = P_b = 3,000 psia
       AOFP = 10,000 BOPD

   (b) P_r = 2,500 psia $P_b > P_r$
       q_o = 100 BPD
       P_{wf} = 1,800 psia

6. Given: P_r = 2,000 psia
          P_b = 1,500 psia
          PI = 4.7 BPD/psi

   construct the IPR curve.

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7. The following data are obtained from a four-point test –

P_r = 2,500 psi P_b = 3,000 psia

Test #	q_o (BPD)	P_{wf} (psia)
1	880	2,000
2	1,320	1,500
3	1,595	1,000
4	1,752	500

Calculate –

1. Value of C and n.

2. Absolute open flow potential where:

$$q_o = C \left(p_r^2 - p_{wf}^2 \right)^2$$

8. The well in Problem #1 is fractured with the best proppant available, and the fracture half-length is 500 ft. Draw the post-frac IPR.

9. Construct IPRs for the following well as a function of permeabilities –

P_r = 2,000 psi r_e = 2,000 ft
S = 0 r_s = 0.5 ft
h = 50 ft B_o = 1.2 RB/STB
μ_o = 2 cp
k = 1, 10, 100, 1,000, 5,000 md

10. For Problem No. 1, assume k = 100 md and construct IPR curves for skin.

Skin = -5, -1, 0, 1, 5, 10, 50, 70

11. Draw a sensitivity of q_o vs S from Problem No. 2.

12. Given –

P_{sep}	=	200 psia	GLR	=	800 scf/bbl
Flowline Length	=	400 ft	F_w	=	0.5
Flowline ID	=	2.5 in.	Tubing ID	=	2.5 in.
Depth	=	5,000 ft	Oil Gravity	=	35 API
Water Sp. Gr.	=	1.074	Gas Sp. Gr.	=	0.65
Bottom Hole Temp.	=	180° F	Surface Temp.	=	60° F

Reservoir data for the construction of an IPR –

P_r	=	4,000 psia	q_o	=	3,000 BPD
P_b	=	3,000 psia	P_{wf}	=	2,000 psia

Draw the IPR and intake curves and predict the flow rate in this well.

13. Make a tubing ID sensitivity and recommend the best tubing size for the following data –

GLR	=	800 scf/stb	API	=	35
γ_g	=	0.65	P_{wh}	=	200 psia
F_w	=	0	T	=	140° F
Depth	=	5,000 ft	Tubing ID	=	2, 2.5, 3, 4 in.

IPR from Problem No. 1

14. Make a completion sensitivity study for the following well –

P_{wh}	=	200 psia	GLR	=	800 scf/STB
API	=	35	F_w	=	0 (all oil)
γ_g	=	0.65	B_o	=	1
r_p	=	0.021 ft	r_c	=	0.063 ft
l_p	=	0.883 ft	k_p	=	0.4K
r_e	=	2,000 ft	h	=	25 ft
P_r	=	3,000 psia	h_p	=	20 ft
r_w	=	0.365 ft	k	=	20 md
μ_o	=	1.2 cp	Tubing ID	=	2.0 in.
Depth	=	5,000 ft			

Use the McLeod equations.