Acidization Job Design using Pressure Transient Analysis

Thesis Submitted in partial fulfilment of the requirements for the degree of

Bachelor of Technology

(Applied Petroleum Engineering)

By

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UNDER THE GUIDANCE OF

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To the best of our knowledge and belief the work has been based on investigation made by them and has not been submitted in any other university or institution for the award of degree/diploma.

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ABSTRACT

To maintain pressure control during drilling, completion or work over of a well the operations are usually done at overbalance condition, these overbalanced conditions results in influx of fluids and solids from wellbore into formation. The net effect of the invading fluid interaction with the formation is generally detrimental. The result is near wellbore formation damage causing additional pressure drop in the vicinity of wellbore and a reduction in well productivity.

Acidizing is a matrix treatment that is a treatment carried out at a pressure lower than the formation breakdown pressure whereby acid is injected into the formation to improve well productivity. The type of acid to be used depends on the type of formation.

Thesis involves well test interpretation for calculation of skin factor, designing calculations like optimum injection rate, concentration of acid, additives, volume of acid mixture etc.

CONTENTS

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NOMENCLATURE

k – Permeability of the formation, milli Darcy

k_S – Permeability of the invaded zone, m

q – Flow rate of fluid, m^3/s

p – Pressure of the reservoir fluid, psi

p_s – Pressure due to skin, psi

p_{wf} – Flowing bottomhole pressure, psi

t – Time in seconds

Ø – Porosity of the formation

ρ – Density of the fluid, kg/m^3

μ – Viscosity of the fluid, cP

ν – Poisson's ratio

FG – Fracture gradient of the formation

i – Injection rate, m^3/s

V – Volume of the acid, m^3

S – Skin factor

r_e – Drainage radius, m

r_w – Radius of the wellbore, m

r_s – Radius of the invaded zone, m

$D_a^{(R,F)}$- Radial Damkohler number for fast reacting minerals

$D_a^{(R,S)}$ – Radial Damkohler number for slow reacting minerals

$A_c^{(F)}$- Acid capacity number for fast reacting minerals

$A_c^{(S)}$- Acid capacity number for slow reacting minerals

$\varepsilon_f^{(R)}$ - Reaction front distance, m

δ – Reaction zone width, m

Ψ- Acid concentration ratio on the upstream side

h – Thickness of the formation, m

r_w' – Effective radius in the presence of skin

c_{HF}^0 – Acid concentration in Kg mole / m^3

β_F – Moles of mineral per mole of HF

S_2 – New skin factor after the treatment

HF – Hydrofluoric acid

HCL – Hydrochloric acid

IARF – Infinite acting radial flow

Chapter 1 Introduction

Well stimulation techniques are applied on a regular basis to enhance productivity and maximize recovery in oil and gas wells. Among these techniques, matrix acidizing is probably the most widely performed job because of its relative low cost, compared to hydraulic fracturing, and suitability to both generate extra production capacity and to restore original productivity in damaged wells. The acidizing process leads to increased economic reserves, improving the ultimate recovery in both sandstone and carbonate reservoirs.

Matrix acidizing consists of injecting an acid solution into the formation, at a pressure below the fracture pressure to dissolve some of the minerals present in the rock with the primary objective of removing damage near the wellbore, hence restoring the natural permeability and greatly improving well productivity. Reservoir heterogeneity plays a significant role in the success of acidizing treatments because of its influence on damage removal mechanisms, and is strongly related to dissolution pattern of the matrix The standard acid treatments are HCl mixtures to dissolve carbonate minerals and HCl-HF formulations to attack those plugging minerals, mainly silicates (clays and feldspars).

Well testing plays significant role for successful execution of acidization treatment. It provides necessary information required for designing of acidization job like skin factor, extent of radial damage, average reservoir permeability etc. Data obtained during well testing operation is studied with the help of testing software(SAPPHIRE). With the help of software using semilog plot skin, average permeability can be determined. It also has importance in post acid job evaluation. Effectiveness of acidization job is gauged in terms of increment in productivity index. Ratio of productivity index requires skin factor which has to be calculated real time. Real time monitoring of skin facilitate any modification during execution of job as well as determine productivity index ratio.

Techniques for real-time monitoring include the methods of McLeod, Coulter and Paccaloni In addition to it new technique that allows the calculation of the initial skin effect, undistorted by acid, and its real-time evolution, developed by Prouvost and Economides. In McLeod and Coulter's technique each stage of injection or shut-in during the treatment is considered as a short individual well test which is studied by conventional pressure transient analysis. Drawback of this method is that reactive fluid keep changing skin while collecting downhole pressure which should be constant for particular set of pressure data. Paccaloni method uses instantaneous pressure and rate values to compute the skin factor at any given time during the treatment, certain assumptions in this method leads to excess calculation of skin which causes more acid injection. Prouvost and Economide is technique that allows a continuous calculation of the skin factor during the course of the treatment. This technique is based on a continuous comparison of measured and simulated pressures and provides most reliable value.

Additives like corrosion inhibitor, surfactants, organic solvents etc are also added in acid mixture to make acidization efficient. Additives are added to prevent precipitation of any insoluble reaction products. In case of multilayer reservoir, acidization is performed with proper acid placement techniques and diverting agents(Ball sealers, Straddle packer, Polymers).

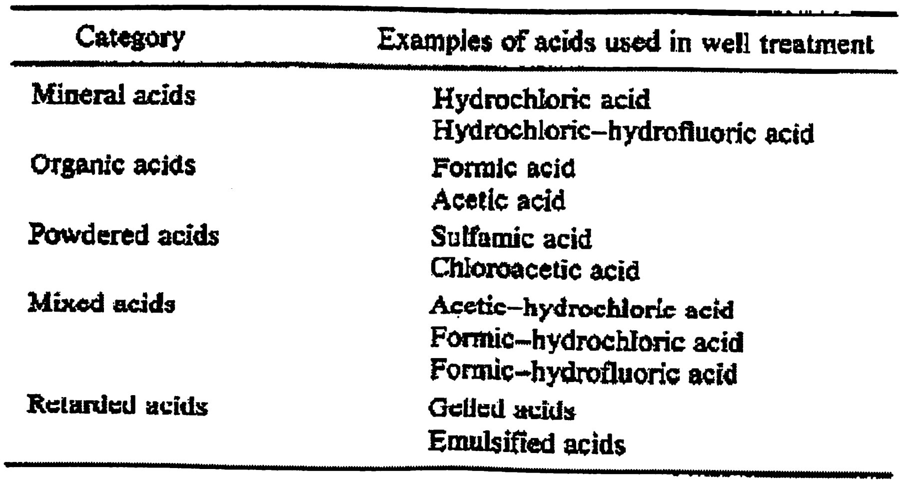
Literature Review

Acids

Acids are used for matrix treatments, as fracturing fluids, for scale removal and to clean up gravel packs. To be able to select the appropriate acid for the required treatment it is necessary to understand the chemical reaction of different acid with reservoir minerals.

Acid systems

Acid system in current use can be classified as mineral acids, dilute acids, powdered organic acids, hybrid acids or retarded acids. The most common members of each category is listed in the underlying table-



Category	Examples of acids used in well treatment
Mineral acids	Hydrochloric acid Hydrochloric–hydrofluoric acid
Organic acids	Formic acid Acetic acid
Powdered acids	Sulfamic acid Chloroacetic acid
Mixed acids	Acetic–hydrochloric acid Formic–hydrochloric acid Formic–hydrofluoric acid
Retarded acids	Gelled acids Emulsified acids

Table 1.1 Categories of acids and example systems.

All of these acids with the exception of HCL-HF and HCOOH-HF acid mixtures are used to treat carbonate formations. It is with this exception, it is necessary to include hydrofluoric acid in the treatment of sandstone formations.

Stoichiometry of Acid-Carbonate reactions

Stoichiometry refers to the proportion of various reactants that enters into the reaction. These proportions can be easily identified in the reaction of calcium carbonate or dolomite with HCL, in addition to HCL other organic acids can also be used to treat carbonate formations. The reactions are-

$$\underset{\text{(calcite)}}{2HCl + CaCO_3} \rightleftharpoons CaCl_2 + H_2O + CO_2$$

and $$\underset{\text{(dolomite)}}{4HCl + CaMg(CO_3)_2} \rightleftharpoons MgCl_2 + CaCl_2 + 2H_2O + 2CO_2$$

Dissolving power(β)

The gravimetric dissolving power is defined as mass of rock dissolved per unit mass of acid. Given the reaction stoichiometry, dissolving power can be easily calculated as following-

$$\beta = \left[\frac{\text{1 mole } CaCO_3}{\text{2 moles } HCl}\right]\left[\frac{\text{molecular weight } CaCO_3}{\text{molecular weight } HCl}\right]\left[\frac{\text{mass } HCl}{\text{mass acid solution}}\right] \quad \text{...(1.1)}$$

An even more useful concept is the volumetric dissolving power (X), which is defined as the volume of rock dissolved per unit volume of acid reacted. The volumetric dissolving power is related to the gravimetric dissolving power simply by the equation-

$$X = \beta \frac{\rho_{acid}}{\rho_{rock}} \quad \text{---(1.2)}$$

The dissolving power of various acids is listed below-

Formation	Acid	β_{100}	X			
			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_3COOH)	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

Data for organic acids have not been corrected for equilibrium.

β_{100} denotes gravimetric dissolving power for 100% strength acids.

Table 1.2 Dissolving power of various acids.

When an acid reaction reaches equilibrium the dissolution of formation materials by the acid stops, even though the acid molecules may still be present. Equilibrium is attained when the chemical activity of the reaction products balances the chemical activity of the reactants.

Consider a general reaction

$$A + B \rightleftharpoons C + D$$

The equilibrium constant for this reaction is defined as

$$K = \frac{a_C a_D}{a_A a_B} \text{--} (1.3)$$

The quantity a_i is the activity of component i. these activities are thermodynamic potentials. The activity of the component increases with its concentration in the solution but they do not exhibit a linear relationship.

Reaction Equilibrium

Under reservoir condition organic acids does not react to completion with either limestone or dolomite because of the limitations imposed on the chemical equilibrium. Equilibrium occurs in reservoir because CO_2 is held in solution by reservoir pressure and is not allowed to escape from the solution. At low pressure however CO_2 can escape and acid reaction reaches to equilibrium. It has been found that equilibrium state can be predicted approximately by the empirical equation-

$$1.6 \times 10^4 K_D = \frac{c_{CaA_2} c_{CO_2}}{c_{HA}} \text{---} (1.4)$$

Here c_i is the concentration of component I in g moles/1000 gm of H_2O. Once the extent of reaction is determined the correct dissolving power can be obtained.

Stoichiometry of Acid-Sandstone reactions

For treating sandstone formations normally a mixture of HF-HCL is employed. An acid mixture is employed here because HF reacts with clay minerals and feldspars that may be restricting the permeability near the wellbore. Chemical reactions between HF and silica or calcite is comparatively simple but HF reactions with aluminosilicates such as clays or feldspar is quite complex.

Equations describing the reaction of HF with silicates (SiO_2) are as follows-

$$SiO_2 + 4HF \rightleftharpoons SiF_4 + 2H_2O$$

$$SiF_4 + 2HF \rightleftharpoons H_2SiF_6$$

The reaction products are highly soluble in water. In the presence of large excess of HF the reaction product is H_2SiF_6 whereas if SiO_2 is in excess the reaction product is primarily SiF_4, depending on which product dominates the dissolving power may vary.

HF reacts with $CaCO_3$ as follows-

$$CaCO_3 + 2HF \rightleftharpoons CaF_2 + H_2O + CO_2$$

The reaction product CaF_2 is not soluble in water and thus this may lead to permeability loss, for the same reason a preflush of HCL is employed for treating sandstone formation.

The reaction of HF and HCL mixtures with aluminosilicates such as feldspars and clays is as follows-

$$NaAlSi_3O_8 + 14HF + 2H^+ \rightleftharpoons Na^+ + AlF_2^+ + 3SiF_4 + 8H_2O$$

The reaction products AlF_2^+ and SiF_4 will be predominate once formed for a limited range of solid to acid ratios.

Equilibrium in Acid-Sandstone reactions

Solutions of HF and HCL mixtures contain many species including H^+, F^-, HF_2^-, HF and Cl^-. Which of these will be present in dominant concentration depends on the concentration of HF and HCL in the solution.

Association of HF is represented as-

$$HF \rightleftharpoons H^+ + F^-$$

$$2HF \rightleftharpoons HF_2^- + H^+$$

And the equilibrium constant is defined as

$$K_D = \frac{[H^+][F^-]}{[HF]} \quad \text{--(1.5)}$$

And

$$K_D = \frac{[H^+][HF_2^-]}{[HF]^2} \quad \text{.--(1.6)}$$

For the respective association.

We note that in presence of an excess amount of clay, the aluminum fluoride compounds are more stable than are the silicon fluorides and the initial reaction product H_2SiF_6 begins to loose fluorine to more stable aluminum compound, as the reaction proceeds ultimately $Si(OH)_4$ is formed and these precipitates may be damaging to the rock permeability and thus should be minimized.

Acid Treatment

In this section matrix acidizing of both sandstones and carbonates is discussed. The treatment is described as the injection of acid into the formation porosity at a pressure lower than the fracture pressure of the formation. Matrix acidizing is most useful in treating highly permeable but damaged zones, if carried out successfully then matrix acidizing leads to increase in production of oil without subsequently increasing water and gas production as the case may be.

Acid is also used in washing the perforation, removing scale deposits on tubular goods by spotting the acid in the wellbore and allowing it to react without agitation.

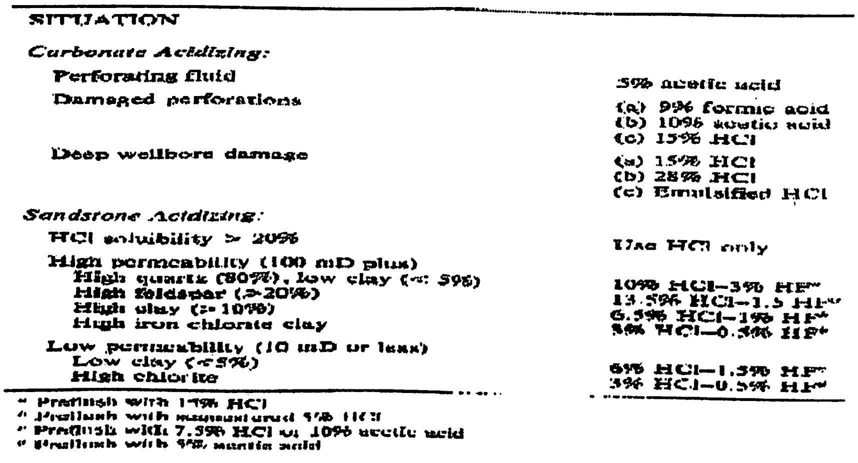
Acids are also used for acid fracturing and the following purposes-

- As a spearhead when fracturing to clean out perforation.
- To break acid sensitive gels used in fracture treatment.
- As a preflush before squeeze cementing.
- Acidizing a completed gravel pack when the permeability of the gravel pack is impaired.

Types Of Acid

In matrix acidizing various acids may be appropriate depending on the particular situation. Any choice of the treatment acid should be derived from consideration of the specific problem with utilization of all the available information. Matrix acidizing involves the concentration of the acid, the volume of the acid to be injected at an appropriate injection rate. Matrix acidizing of sandstone also includes an preflush and an afterflush. The appropriate formulation depends on the mineralogy and the petrology of the formation rock.

Following table has been prepared by McLeod as a guideline for the acid selection.



SITUATION	
Carbonate Acidizing:	
Perforating fluid	5% acetic acid
Damaged perforations	(a) 9% formic acid (b) 10% acetic acid (c) 15% HCl
Deep wellbore damage	(a) 15% HCl (b) 28% HCl (c) Emulsified HCl
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 chlorate clay	5% 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

Table 1.3 Guidelines for acid selection.

Acid is injected into the formation by pumping it from the surface containers and through tubing, all the materials that come in contact with the acid should be thoroughly cleaned otherwise the acid insoluble solid deposits (oxide scale, pipe dope, paraffin, asphaltene) will all be carried to the formation creating further damage. If the reservoir pressure is too low to lift the acid back a foamed acid should be used, proper spotting of acid is also crucial. To be successful it is necessary that the acid must be directed, directly to the damaged zone.

Theoretical Productivity Improvement

A matrix acidizing treatment is effective primarily in the damaged zone near the wellbore. In this system a zone of reduced permeability (k_s) extends from the wellbore radius (r_w) to a radius of r_s, beyond this the formation has a constant permeability of k to the drainage radius r_e.

$$\frac{J_d}{J_0} = \frac{(k_s/k)\ln(r_e/r_w)}{\ln(r_s/r_w) + (k_s/k)\ln(r_e/r_s)} \tag{1.7}$$

Here J_o is the productivity index of the undamaged formation and J_d of the same damaged formation.

Maximum Injection Rate

The well pressure p_{wf} to inject the fluid into the formation having a drainage radius of r_e and the reservoir pressure p_R, is given by-

$$p_{wf} - p_R = \frac{i\mu}{2\pi kh}\left[\ln\left(\frac{r_e}{r'_w}\right) - \frac{3}{4}\right] \tag{1.8}$$

Here r'_w is the effective radius in the presence of skin, given by

$$r'_w = r_w \exp(-S) \tag{1.9}$$

The maximum injection rate i_{max} is found when

$$P_{wf} = (FG) * D \tag{1.10}$$

FG here is the fracture gradient and D is the formation depth.

Acid Reaction With Reservoir Minerals

Acid reactions with reservoir minerals are heterogeneous reactions since they occur at the interface between solid and liquid rather than in the bulk phase. The observed overall reaction is represented by disappearance of the acid from the solution. The disappearance of acid is composed of various mechanism occurring in the series, it is important to understand all of these steps since one of the steps is the slowest step and the rate at which this slowest step progresses determines the overall rate of reaction. Upon changing the thermal and chemical environment the rate controlling step also changes.

The observed reaction rate is the time rate of change of concentration of one component in the bulk liquid phase. The rate of acid transfer to the reactive mineral surface by diffusion, forced convection, free convection or fluid loss is the first step. The second step is the reaction rate determined by the kinetics of the surface reaction.

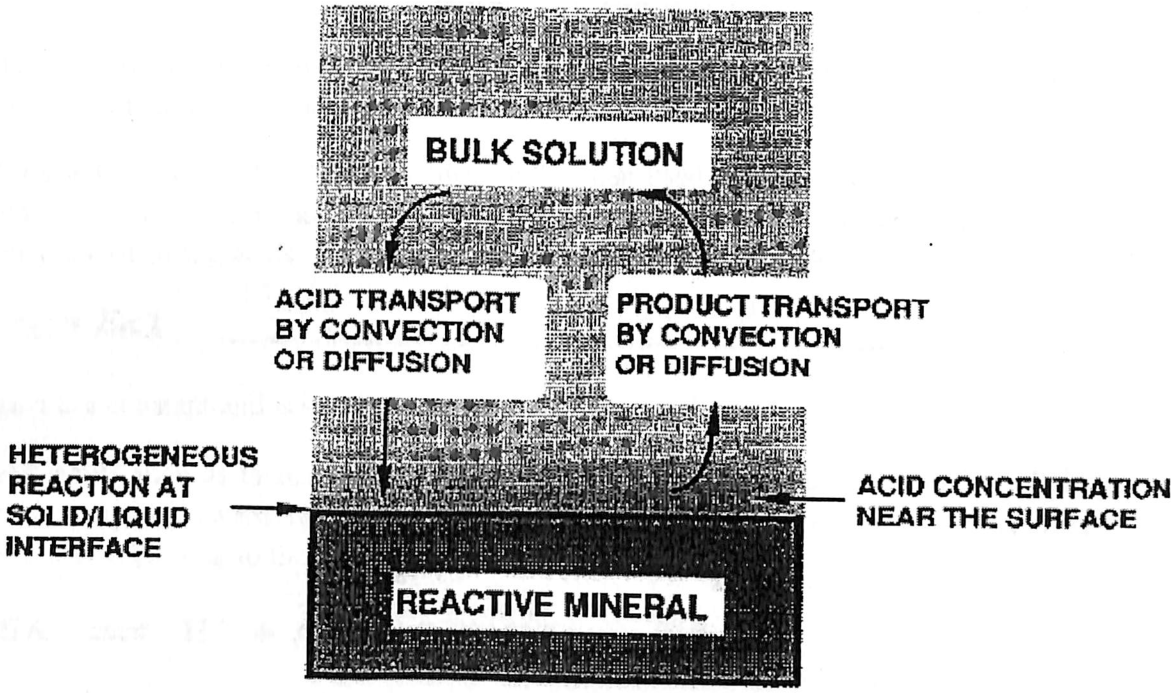


Fig 1.1 .Schematic diagram of the system in which acid reaction occur.

Rate Of Surface Reaction

The rate of the heterogeneous reaction is a function of the chemical composition of the liquid phase evaluated near the surface, such concentration are called as surface concentration. And further these surface concentrations can be related to the bulk phase concentration.

The rate of heterogeneous reaction is generally expressed as an amount of chemical species produced per unit of surface per unit of time. The surface area refers to the mineral solution wetted area.

Consider a heterogeneous reaction of HCL with calcium carbonate-

$$2H^+ + CaCO_3 \underset{E_R}{\overset{E_f}{\rightleftharpoons}} CO_2 + Ca^{++} + H_2O$$

Or, in symbolic terms-

$$2A + B \underset{E_R}{\overset{E_f}{\rightleftharpoons}} C + D + E$$

For this reaction a general rate expression is-

$$-r_A - E_f c_A^{\alpha} c_B^{\beta} - E_R c_C^{\gamma} c_D^{\delta} c_E^{\epsilon} \quad \text{---}(1.11)$$

Here, c_i is the surface concentration of the component i, E_f and E_b are the forward and backward reaction rate constants.

Strong acids such as highly dissociated HCL when used to treat formation, the reaction essentially goes to completion and thus the backward rate will be negligible in most application of strong acids, and thus the reaction rate expression reduces to

$$-r_A = E_f c_A^{\alpha} \quad \text{---}(1.12)$$

Here α is a constant and is known as the order of the reaction.

Weak acids such as formic, acetic, propionic and other organic acids dissociate slightly and thus the backward reaction rate cannot be neglected in this case. An acid HA dissociates according to the relation

$$\mathrm{HA} \rightleftharpoons \mathrm{H^+} + \mathrm{A^-}$$

With equilibrium described by dissociation constant (K_d) defined as

$$K_d = \frac{c_H c_A}{c_{HA}} = \frac{c_{H^+}^2}{c_{HA}} \quad \text{--}(1.13)$$

And thus the rate expression is given as

$$-r_A = E_f c_H^{\alpha} - E_R c_{CO_2}^{\alpha/2} c_{Ca}^{\alpha/2} \quad \text{---}(1.14)$$

Feldspar-Hydrofluoric reactions.

The silicates primarily feldspars, clays with the exception of chlorite does not react with HCL. These minerals do however react with HF. Feldspar may be divided into two major groups: the orthoclase group and the plagioclase group. The dissolution kinetics of feldspar in HF-HCL mixtures are found to obey the following rate law-

$$+r_{feldspar} = E_f[1 + K(c_{HCl})^{\beta}](c_{HF})^{\alpha}$$ ---(1.15)

For **potassium feldspar (orthoclase)** the kinetic parameters have the following values

$$\beta = 0.4; \qquad \alpha = 1.2$$

And the rate constant obeys the following relation-

$$E_f = 1.27 \times 10^{-1} \exp\left(-\frac{4680}{T}\right) \quad \text{and} \quad K = 5.66 \times 10^{-2} \exp\left(\frac{956}{T}\right)$$ (1.16)

For **sodium feldspar (albite)** the kinetic parameters representing the kg moles of albite per m^2 per sec have the following values-

$$\beta = 1.0; \qquad \alpha = 1.0$$

$$\text{and} \quad E_f = 9.50 \times 10^{-3} \exp\left(-\frac{3930}{T}\right); \quad K = 6.24 \times 10^{-2} \exp\left(\frac{554}{T}\right)$$ ---(1.17)

These rate expressions are expressed in terms of orthoclase or albite which enters the solution.

Quartz-Hydrofluoric reactions.

The reaction rate of quartz with HF has been investigated by Bergman. At 298 Kelvin

$$r_{HF} = -E_f c_{HF}$$ ---(1.18)

This rate is expressed in terms of Kg moles of HF reacted per m^2 per sec, and the E_f expression is given by-

$$E_f = 1.39 \times 10^{-7} \exp\left(-\frac{1150}{T}\right)$$ ---(1.19)

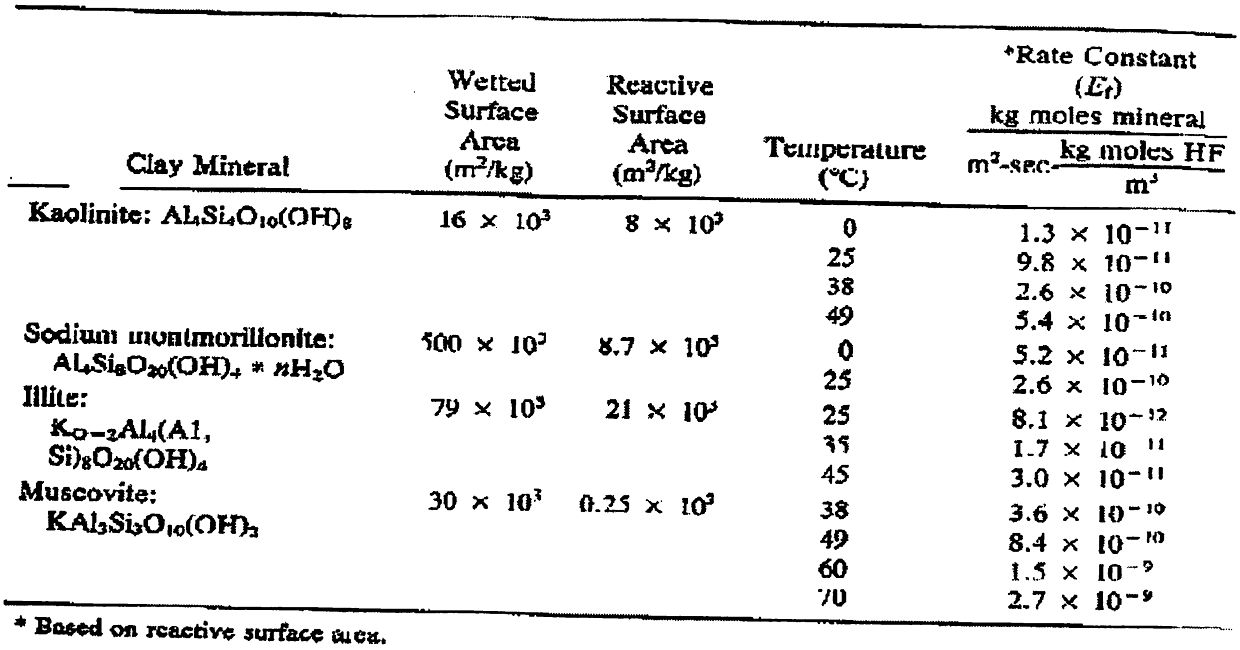
Clay-Hydrofluoric reactions.

The reaction of clay minerals with HF has been investigated by Kline and Fogler. The clay reactivity was found not to be proportional to the surface areas of the clay in contact with the acid solution, the surprising difference in the reaction rates per unit area can be understood in terms of the respective crystalline structure of clays. Kaolinite is two layer clay with a alumina and silica sheet bound together whereas montmorillonite is a three layer clay in which a alumina sheet is sandwiched between two silica sheets. Thee alumina sheet is much more reactive than silica and thus for the same reason kaolinite tends to be attacked faster than montmorillonite. Acid reacts with alumina sheets producing holes that expose other layers to the acid, whereas montmorillonite on the other hand tends to dissolved from the edges first; the actual reactive area of the montmorillonite is thus only a small fraction of the exposed area and kaolinite reacts much faster.

The rate constants can also be expressed in terms of the aluminum produced. The rate of dissolution of clay is given by-

$$r_{clay} = -E_f C_{HF} \qquad (1.20)$$

E_f is the forward rate constant obtained from the underlying table for different clays.



Clay Mineral	Wetted Surface Area (m^2/kg)	Reactive Surface Area (m^2/kg)	Temperature (°C)	*Rate Constant (E_f) $\frac{\text{kg moles mineral}}{m^2\text{-sec-}\frac{\text{kg moles HF}}{m^3}}$
Kaolinite: $Al_4Si_4O_{10}(OH)_8$	16×10^3	8×10^3	0	1.3×10^{-11}
			25	9.8×10^{-11}
			38	2.6×10^{-10}
			49	5.4×10^{-10}
Sodium montmorillonite: $Al_4Si_8O_{20}(OH)_4 * nH_2O$	500×10^3	8.7×10^3	0	5.2×10^{-11}
			25	2.6×10^{-10}
Illite: $K_{0-2}Al_4(Al, Si)_8O_{20}(OH)_4$	79×10^3	21×10^3	25	8.1×10^{-12}
			35	1.7×10^{-11}
			45	3.0×10^{-11}
Muscovite: $KAl_3Si_3O_{10}(OH)_2$	30×10^3	0.25×10^3	38	3.6×10^{-10}
			49	8.4×10^{-10}
			60	1.5×10^{-9}
			70	2.7×10^{-9}

* Based on reactive surface area.

Table 1.4 Forward rate constants for different clays.

hapter 2 Well Testing & Well Test Interpretation

Well Testing is performed on an oil or gas well after cementing in order to obtain the following information:

- Reservoir pressure and temperature
- Reservoir fluid type, samples for reservoir analysis.
- Deliverability of the well.
- Wellbore storage, skin and permeability.
- Inflow Performance of the well (PI/AOFP)
- Commercial viability of the well.
- Réservoir description (bouderies, faults, etc.)

A reservoir test can be performed only under dynamic conditions, which means that the reservoir must be exposed to a disturbance that will cause the reservoir pressure to change. The pressure change is recorded and interpreted in conjunction with the measured flow rates to yield information about the parameters and geometry of the well and reservoir.

Estimation of the formation's flow capacity, characterization of wellbore damage, etc. require a transient test because a stabilized test is unable to provide unique values for mobility-thickness and skin. Transient tests are performed by introducing abrupt changes in surface production rates and recording the associated changes in bottom hole pressure.

Production changes, carried out during a transient well test, induce pressure disturbances in the wellbore and surrounding rock. These pressure disturbances travel into the formation and are affected in various ways by rock features. For example, a pressure disturbance will have difficulty entering a tight reservoir zone, but will pass unhindered through an area of high permeability. It may diminish or even vanish upon entering a gas cap.

Therefore, a record of wellbore pressure response over time produces a curve whose shape is defined by the reservoir's unique characteristics. Unlocking the information contained in pressure transient curves is the fundamental objective of well test interpretation.

The pressure analysis techniques have been derived from solutions of the partial differential equations describing flow of fluids through porous media for various boundary conditions and that is the diffusivity equation. The diffusivity equation is derived from three different physical principles, which are-

a) The law of conservation of mass
b) Darcy's law.
c) The equation of state.

To derive the diffusivity equation in its simplest form several assumptions have to be made :

- The reservoir is homogeneous.
- Fluid flow is horizontal.
- The fluid is monophasic and slightly compressible.
- Pressure gradients are small.

For radial flow, combining the three physical principles and the above made assumptions, the diffusivity equation is given by-

$$\frac{\partial p}{\partial t} = \frac{k}{\phi \mu C_t}\left[\frac{\partial}{\partial r}\left(\frac{\partial p}{\partial r}\right) + \frac{1}{r}\left(\frac{\partial p}{\partial r}\right)\right] \quad \text{..(2.1)}$$

The solution to the diffusivity equation describes the flow of a slightly compressible liquid in a porous medium. There are four solutions that are particularly useful in well testing, these are, solution for

a) Bounded cylindrical reservoir.
b) Infinite reservoir with a line source well.
c) Pseudo steady state solution.
d) Solution that includes wellbore storage for a well in a infinite reservoir.

Skin

In practise we find that during drilling, completions, cementing and perforating most of the wells have reduced permeability near the wellbore, this zone of reduced permeability is characterized by skin effect and signifies the excess pressure drop taking in this damaged zone. The reason for this is that the reservoir near the wellbore has been invaded by drilling fluids and has undergone changes in permeability, absolute or relative to the reservoir fluids.

Some of these changes are reversible during the 'clean-up' period when the well is first put on production while others are not.

Hawkins pointed out that if the damaged zone or stimulated zone is considered equivalent to an altered zone of uniform permeability (k_x) and outer radius (r_s), the additional pressure drop (Δp_s) across this zone can be modelled by the steady-state radial flow equation.

It simply states that the pressure drop in the altered zone in inversely proportional to ks .

The skin effect can better be modelled as

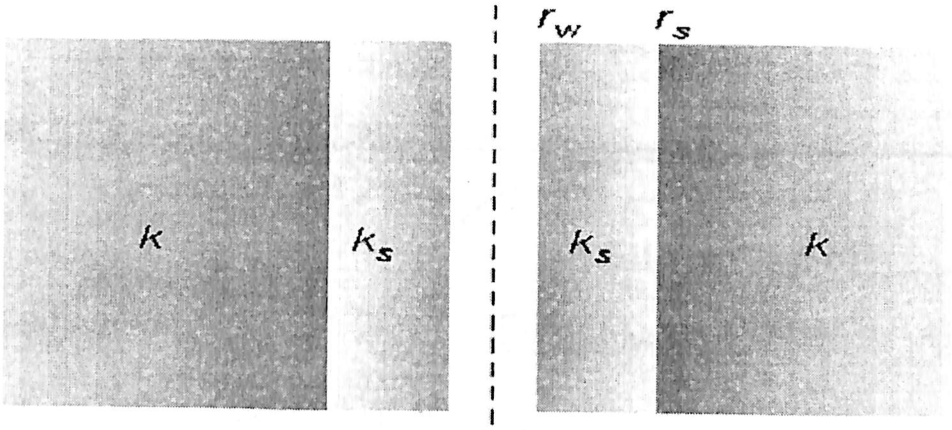


Fig 2.1 Skin (Openhole)

And

$$\mathbf{S = [K/K_S - 1] \ln (r_S/r_w)} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2.2)$$

The above definition of skin shows that the the skin factor terms to be zero if the permeability of the altered zone is same as that of the reservoir permeability or if the invaded or damaged zone extends to rw.

This mathematical description of the skin is not realistic as there will be no two discrete zones as shown with a clear boundary in between them and thus what we are interested is the excess pressure drop taking in the damaged zone which decreases the productivity index (PI) of the well, this skin causing an excess pressure drop in the region near the wellbore can be removed by acidization.

The skin value S is a dimensionless parameter and in most cases is independent of the flow rate, but the corresponding pressure drop (ps) is rate dependent. A positive skin denotes 'damage' whereas a negative skin historically denoted 'stimulation'.

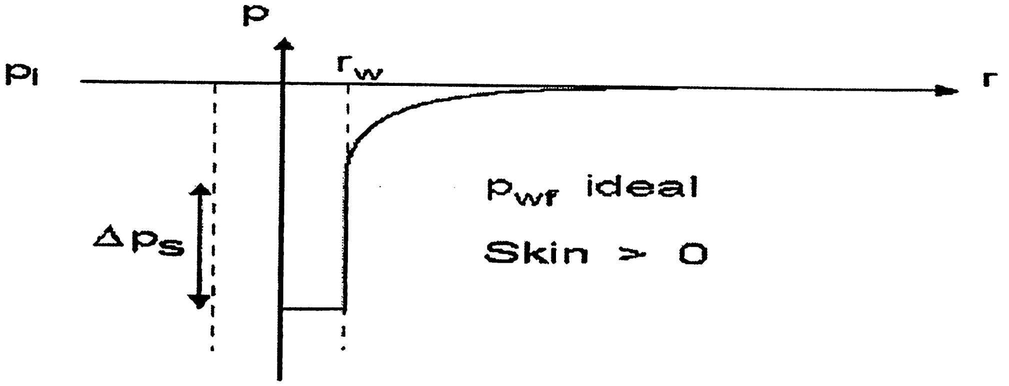


Fig 2.2 Positive Skin

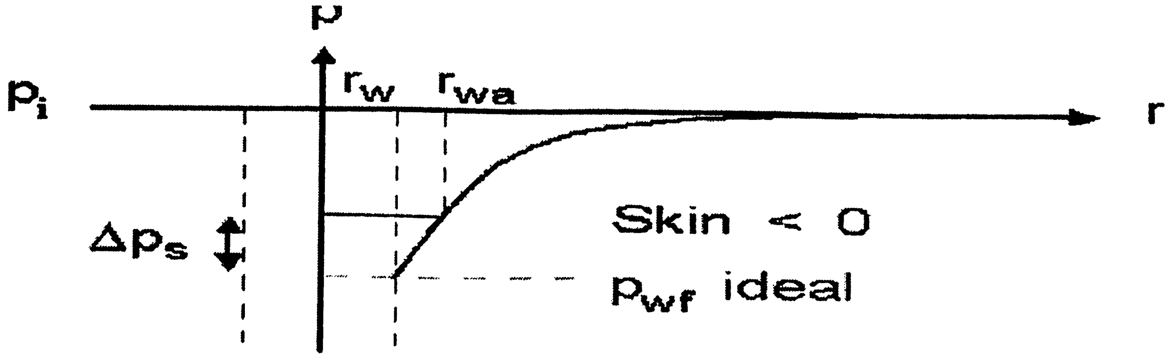


Fig 2.3 Negative Skin

Well Test Data Interpretation

Pressure transient curve analysis provides very useful information about reservoir characteristics. Horizontal and vertical permeability, well damage, fracture length, storativity ratio and interporosity flow coefficient are just a few of the characteristics that can be determined. In addition pressure transient curves can indicate the reservoir's extent and boundary details.

The shape of the curve, however, is also affected by the reservoir's production history. Each change in production rate generates a new pressure transient that passes into the reservoir and merges with previous pressure effects. The observed pressure at the wellbore is a result of the superposition of all these pressure changes.

Different types of well tests can be achieved by altering production rates. Whereas a buildup test is performed by closing a valve (shut-in) on a producing well, a drawdown test is performed by putting a well into production.

Mathematical models are used to simulate the reservoir's response to production rate changes. The observed and simulated reservoir responses are compared during well test interpretation to verify the accuracy of the model. Today's computer-generated models provide much greater flexibility and improve the accuracy of the match between real and simulated data.

The various methods employed for well test interpretation are:

1. Semi Log Approach: (Classical method)
    - Miller-Dyes-Hutchinson or MDH method
    - Horner's Plot method
2. Log-Log Approach (Type Curves)
    - Dimensionless variables and Type Curves
3. Pressure Derivative Method (The diagnostic plot method)
    - Use of Pressure derivative plot with the log-log plot

The semi-log approach to well test interpretation is based upon the identification of this straight line portion of the drawdown or build-up data, from which the permeability-thickness product, kh and the skin damage S are obtained. MDH plot is the simplest semi-log plot, in which the time axis is log (Δt), but it can only be used for the first ever drawdown in a well. Horner's plot takes into account all the superposition effects, and thus can be used for the analysis of any flow period.

The log-log approach has now superseded the semi-log approach in the industry, as by combining the log-log plot of □ p vs □ t with the pressure derivative, it is possible to make the entire analysis with a single plot. From the simplest homogeneous, infinite model to the most complex heterogeneous, bounded model, the log-log 'diagnostic' plot provides both a qualitative picture of the well and reservoir type and a quantitative evaluation of the parameters.

The pressure derivative is essentially the rate of change of pressure with respect to the superposition time function – i.e., the slope of the semi-log plot. So the basic idea of the derivative is to calculate the slope at each point of the pressure curve on the semi-log (superposition) plot, and to display it on the log-log plot. For example, when the flow at early time corresponds to pure wellbore storage, pressure and pressure derivative curves will merge on a unit slope straight line on the log-log plot.

For most other flow regimes, it will be seen that while the log-log plot reveals little or no relevant information, the pressure derivative always displays a characteristic response.

Its sensitivity to transient features resulting from well and reservoir geometries (which are too subtle to recognize in the pressure change response) makes the derivative curve the single most effective interpretation tool.

The characteristic curve of each reservoir under different conditions varies from each other and the information locked in these curves is the ultimate aim of any well test.

A typical semi log plot is as shown, and gives the relevant information as explained in figure

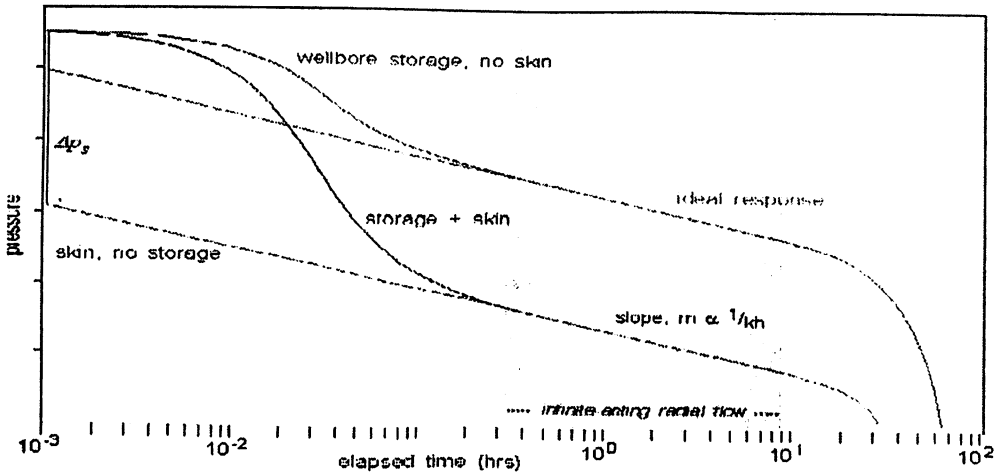


Fig 2.4 Semi log approach.

But what we are interested in here is to calculate the skin factor so that we can signify the extend of damage which has taken place during drilling and other completion services of the wellbore which has caused in a reduction in the PI of the well.

Skin Factor Calculations

The late time approximation to the solution of the diffusivity equation can be given as

$$P_D = \frac{1}{2}[\ln(t_D) + 0.80907 + 2S] \quad \text{.....................................(2.3)}$$

In terms of real pressure and converting to oil field units

$$\Delta p = 162.6\frac{q\mu B}{kh}\left[\log(\Delta t) + \log\left(\frac{k}{\phi\mu C_t r_w^2}\right) - 3.23 + 0.87\ S\right] \quad \text{...........(2.4)}$$

Now, when the semi log approximation for infinite acting radial flow is valid, then a plot of P vs Log (Δt) gives a straight line with a slope m,

$$m = 162.6\frac{q\mu B}{kh} \quad \text{.....................................(2.5)}$$

Here

- Kh is obtainethe equation of m, as all other parameters are known.
- S, is calculated by taking an arbitrary pressure point at Δt=1, so that

$$\frac{\Delta p_{1hr}}{m} = \left[\log\left(\frac{k}{\phi\mu C_t r_w^2}\right) - 3.23 + 0.87\ S\right] \quad \text{...(2.6)}$$

Since all other tems are known so skin factor can be calculated as follows.
MDH plot is used for calculating skin but it is strict ally valid only for the first ever drawdown so we in most of the cases we use Horner plot which uses the pressure build up data to calculate the skin factor.

HORNER PLOT

In the simplest superposition case of a build up following a single drawdown in which an elementary rate –q (injection) overlays a drawdown of +q. Assuming both to reach the IARF assumption, the approximate build up solution is given by,

$$\Delta p_{BU} = p_{BU} - p_{\Delta t=0} = 162.6\frac{q\mu B}{kh}\left[\log\left(\frac{t_p\Delta t}{t_p+\Delta t}\right) + \log\left(\frac{k}{\phi\mu C_t r_w^2}\right) - 3.23 + 0.87\,S\right] \qquad .(2.7)$$

The IARF will be characterized by a linearity between the pressure response and the horner time function Log (tp+Δt)/Δt. Here tp characterize the duration of production preceding the shut in.

The skin calculation requires that the drawdown has reached the IARF solution, so the pressure build up equation becomes

$$S = 1.151\left[\frac{\Delta p_{1hr}}{m} - \log\left(\frac{k}{\phi\mu C_t r_w^2}\right) + \log\left(\frac{t_p+1}{t_p}\right) + 3.23\right] \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(2.8)$$

Now taking the pressure at on the line at 1 hour, the skin equation is given by

$$p = p_i - 162.6\frac{q\mu B}{kh}\log\left(\frac{t_p+\Delta t}{\Delta t}\right)$$

$$\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(2.9)$$

It is difficult to evaluate the pressure at time of 1 hour by hand as it involves calculating the value of time function at t=1 hr, modern softwares calculate it automatically by drawing a line to pressure values at t= 1hr.

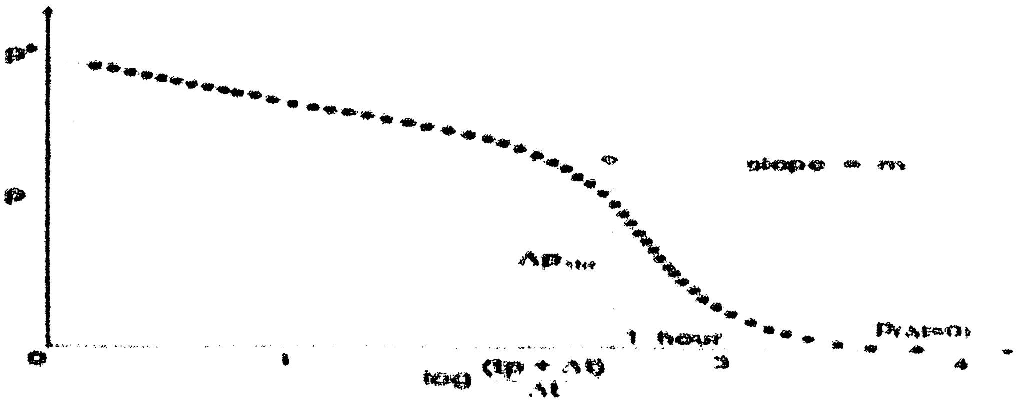


Fig 2.5 Horner's plot

Well Test Interpretation Methodology

Proper test design, correct handling of surface effluents, high-performance gauges, flexible downhole tools and perforating systems, wellsite validation and comprehensive interpretation are key to successful well testing. Design of a well test includes development of a dynamic measurement sequence and selection of hardware that can acquire data at the wellsite in a cost-effective manner. The data to be collected determine the type of well test to be run.

The various flow and build up sequences (pressure transient tests) in DST are:

- Clean up Flow
- Initial Build Up
- A Series of drawdown at various chokes
- Final Build up

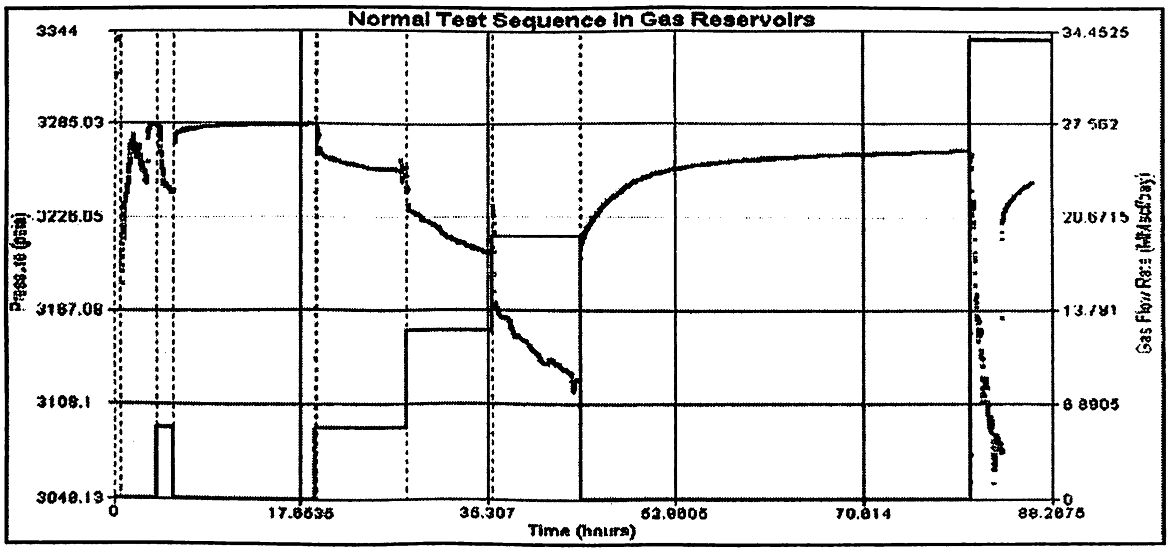


Fig 2.6 Normal Test Sequence in Reservoirs

The objective of well test interpretation is to obtain the most self-consistent and correct results. This can be achieved by following a systematic approach. Comprehensive interpretation of acquired data is critical for efficient reservoir development and management because it quantifies the parameters that characterize the dynamic response of the reservoir.

The analysis of the given well test data, basically involves three steps:

Data processing:

- All the pressure gauge data and flow rate data, for a particular or all events is processed by splitting into individual flow periods.
- Exact determination of start and end of each flow period
- Well test data viz. pressure, gas flow rates and duration of the transient tests are entered into the software for analysis.

Flow Regime Identification:

Identifying flow regimes, which appear as characteristic patterns displayed by the pressure derivative data, is important because a regime is the geometry of the flow streamlines in the tested formation.

The eight flow regime patterns commonly observed in well test data are radial, spherical, linear, bilinear, compression/expansion, steady-state, dual-porosity or -permeability, and slope doubling.

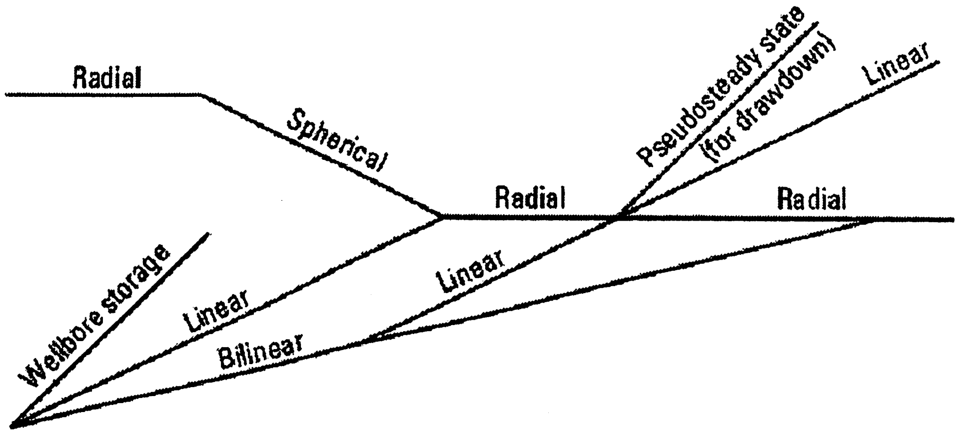


Fig 2.7 Flow Regime Identification.

Modeling:

Model Identification:

A Theoretical reservoir model has to be identified with pressure trends that resemble those observed in the acquired data. Flow regimes have to be correctly interpreted according to the slopes and trends observed in the diagnostic plot, so that the complete reservoir can be modeled along with its boundaries. Reservoir information collected from geoscientists assists the selection of a reservoir model.

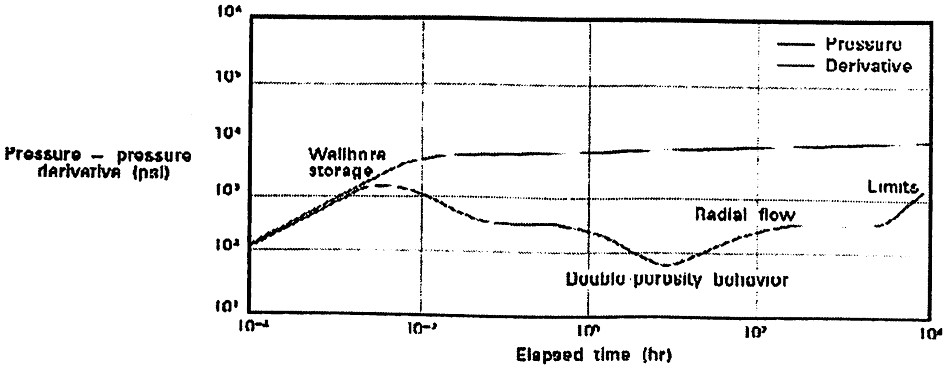


Fig2.8 Model Identification.

Parameter Estimation:

This is needed to compute the model parameters. After the different characteristic regimes have been identified, specialized analyses are performed for calculating various well and reservoir parameters including wellbore storage constant, permeability and skin.

Results Verification:

In this part of the analysis, a well model is defined in terms of an inner boundary condition, reservoir type and outer boundary condition. The parameters (permeability, skin, etc.) obtained from the earlier specialized analysis are fed into the model. The modeling is performed in two distinct steps. First is multi rate type curve matching, in which the theoretical transient response for the well test model with the associated parameters is generated and compared with the recorded pressure transient data. Any mismatch is then removed on a trial and error basis by making changes in the model parameters, and, if need be, even the model components (inner or outer boundary conditions and reservoir type). The software even has nonlinear capability, which determines the most probable values of parameters for a particular model definition so as to provide the best match. In the second step of forward modeling, the entire pressure transient history is simulated on the basis of well test model and model parameters.

Field Data Study: Well Test Interpretation using ECRIN

Procedure for well test interpretation:

Mathematical models are used to simulate the reservoir's response to production rate changes. The observed and simulated reservoir response can then be compared during well test interpretation to verify the accuracy of the model. By altering model parameters such as permeability or the distance from the well to a fault, a good match can be reached between the real and modeled data. The model parameters are then regarded as a good representation of those of the actual reservoir. Today's computer generated models provide much greater flexibility and improve the accuracy of the match between real and simulated data. It is now possible to compare an almost unlimited number of reservoir models with the observed data.

The following steps were performed for the purpose of interpretation of well test data from well X:

- Well test data viz. pressure and time was fed in Sapphire.
- Gas flow rates and duration of the transient tests viz. consecutive drawdown and final build up was also fed.
- Log-Log (both pressure and derivative) and Semi-Log plots for the final build up was obtained using the software.
- A model was fit for the above plots.
  Using sensitivity analysis and non linear regression features of the software, the above model was corrected to match the plots.

Input Parameters:

Fluid Type:	Gas
Rate Type:	Surface rates
Rw:	0.5104 ft
H:	62.336 ft
Phi:	0.15

PVT Parameters

Gas Gravity:	0.554
Pseudo-Critical P:	683.406 psia
Pseudo-Critical T:	339.817 °R
Hydrogen sulphide:	0
Carbon dioxide:	1E-3
Nitrogen:	0
Z:	Standing
µg:	Lee et al.
Cg:	Dranchuk
Temperature:	140 °F
Pressure:	3286 psia

Properties at Reservoir T&P

Z:	0.88138
Mug:	0.019503 cp
Bg:	0.00454817 cf/scf
Cg:	2.66329E-4 psi-1
Total Compressibility, Ct :	2.70439E-4 psi-1
Connate Water (%):	0
Formation Compressibility:	4.1093E-6 psi-1
Reservoir T:	140 °F
Reservoir P:	3286 psia

Parameters

WGR	0 bbl/MMscf
Cf:	4.1093E-6 psi-1
Swr:	0
Minimum Pressure:	14.6959 psia
Maximum Pressure:	10014.7 psia

Results:

The following two models approximately represented the well test data:

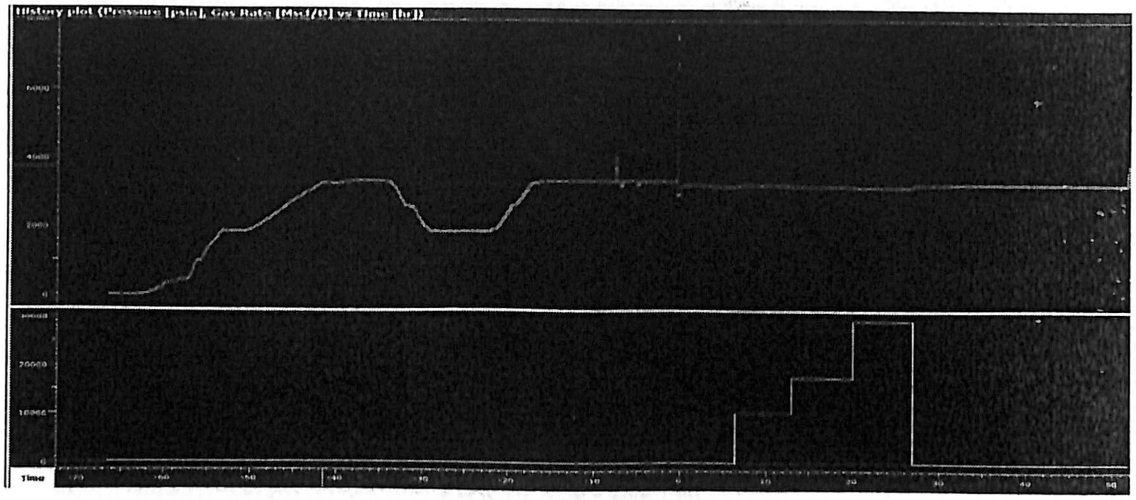


Fig 2.9: History Plot

Selected Model:

Model Option:	Radial composite model
Well:	Vertical
Reservoir:	Homogeneous
Boundary:	Infinite

Main Model Parameters

C:	0.0104 bbl/psi
Total Skin:	0.502
KH total:	8530 md.ft
Kaverage:	104md
Pi:	3265.25 psia
Ri:	80.7ft
M:	0.912
D:	0.282

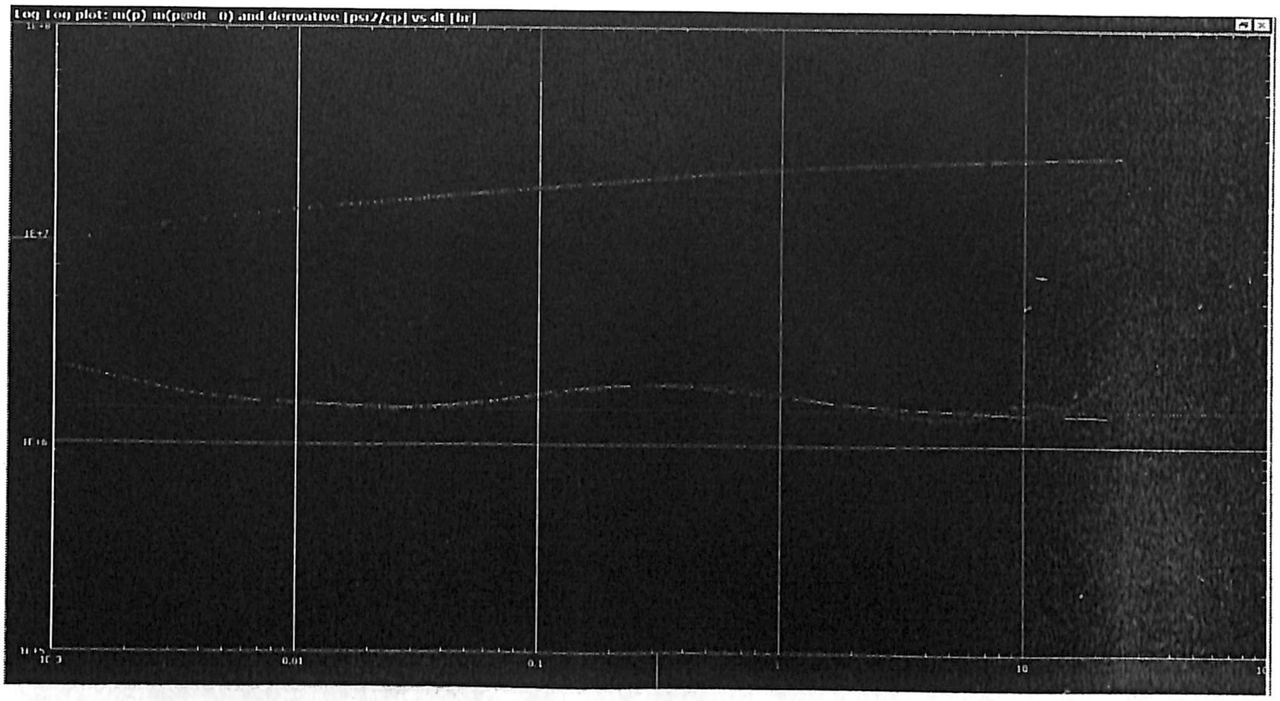


Fig 2.10: Log - Log Plot

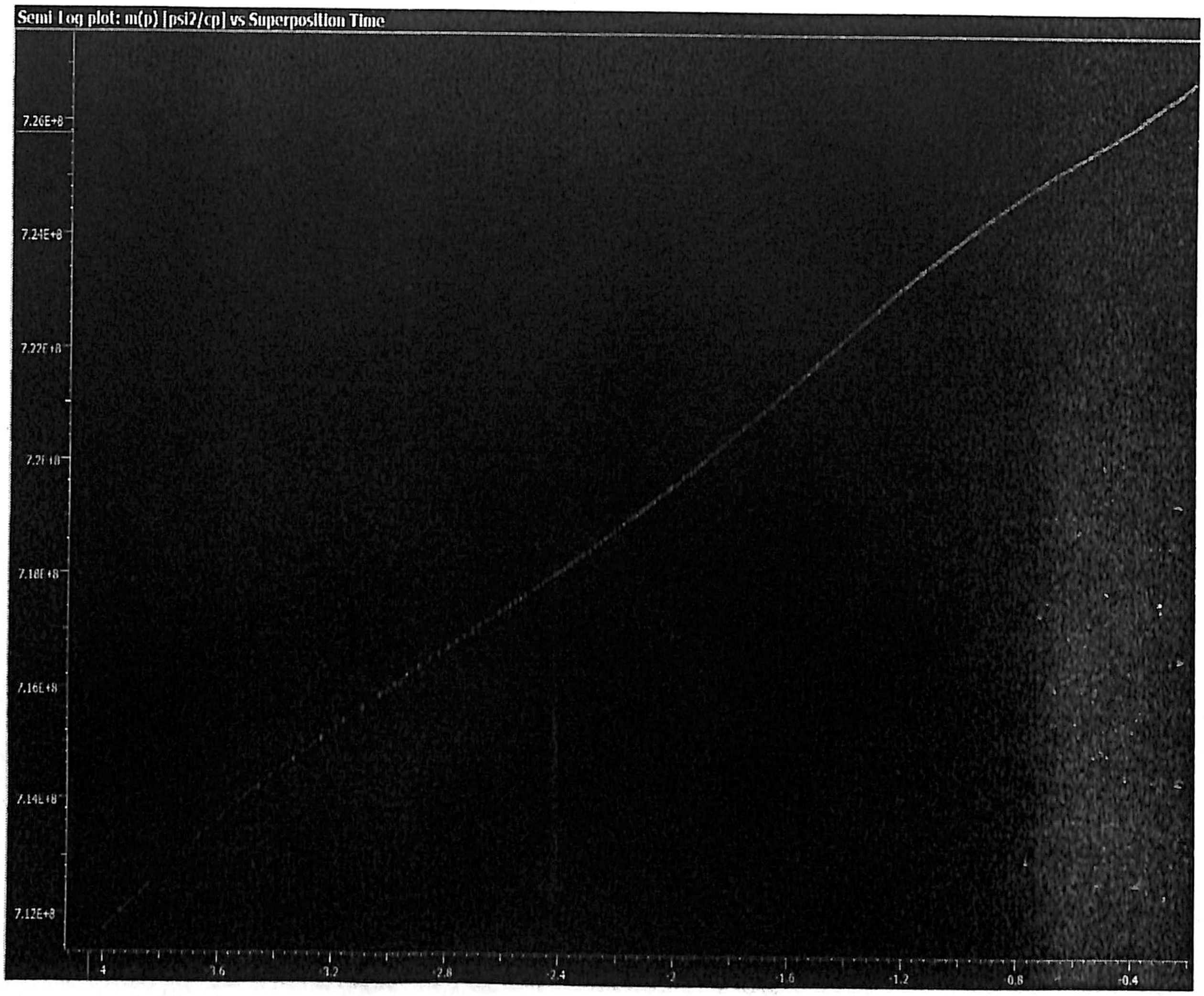


Fig 2.11: Semi Log Plot

Conclusions:

1. The well bore storage factor (C) was found to be very low from all three models as is the case with gas wells. This is revealed from the log-log plot as the unit slope line is absent.
2. This is followed by transition transient leading to radial flow as shown by the zero slope region of the pressure derivative in the log-log plot (Fig. 2.11).
3. The opposite trend in the first drawdown may be due to the immediate start of the first drawdown after the last clean up.
4. The radial composite model with infinite boundary matches the acquired data curves depicting the regions of infinite acting radial flow ..
5. The shape of the transition in the radial composite model is governed by the ratio M/D.

Chapter 3 Formation Damage: Origin and Removal

Origin of formation damage

It describes the origin of formation damage and reviews all the operations on the well, from drilling to cementing, completion, gravel packing, production, stimulation, and injection for enhanced oil recovery. All are potential sources of damages.

Drilling Damage

Drilling mud solid invasions

Particulate materials contained in drilling fluids are potentially damaging: clays, cuttings, weighting agents, and lost-circulation agents. If forced into the pay zone, they can progressively fill the porosity of the reservoir rock. Any subsequent attempt to start production or injection at moderate or high flow rates will cause these materials to bridge over pore throat entries and severely decrease permeability near the wellbore area.

Such a damaging process is limited to the first few. inches around the wellbore (an average value of 3 in. (7.5 cm) is commonly used), but the resultant permeability reduction can be as high as 90%.

Invasion of formation rock by drilling fluid solids is favoured by:

- Large pore size of the formation rock.
- Presence of fissures and natural fractures in the reservoir.
- Small particle size of the solid components of the drilling fluid (weighting agents and lost-circulation preventers whose initial particles are usually coarse and can be fragmented by the drilling bit.
- Llow drilling rate resulting in mudcake destruction (mud loss increase) and long mud-to-formation contact time.
- High drilling fluid circulation rate (mudcake erosion).
- High drilling fluid density causing large overbalanced pressure .
- Scrapping mudcake, provoking pressure surges and increasing formation-to-mud contact time during bit trips

Using clear brines (containing no particulate materials) as drilling fluids minimizes formation invasion by fines. Using brines without fluid-loss agents does not necessarily increase filtrate invasion: cuttings debris can aid in fluid-loss prevention. The chemical nature of clear brines (high-salinity and clay-stabilizing cations such as calcium or zinc) partly prevents their filtrates from damaging the formation.

Drilling Fluid Filtrate Invasion

Drilling filtrate damage is probably one of the most important causes of production impairment. .Liquid phase of drilling fluid contains many potentially damaging compounds. Damage by drilling fluid invasion can be upto 15 ft.For economic reasons, wells have to be drilled as fast as possible. To increase the penetration rate, it is tempting to reduce the fluid-loss control of the mud Higher values of filtrate invasion may result from the deliberate choice of high penetration rates.Extent of damage depends upon sensitivity of formation to the filtrate. High-permeability clean sandstones (although undergoing more invasion than low-permeability reservoirs.) are usually not affected when their connate water is chemically compatible with the filtrate.

Sensitive formations are those containing clays that can be dispersed and/or swollen, or those low-permeability rocks in which saturation problems dominate, or those reservoirs producing almost saturated brines or high asphaltene or paraffin content oils. Incompatibility of filtrate with pore fluids lead to unstability of clay particles into porous medium.Destabilized formation fines act similarly to mud particles forced into formation rocks. As production or injection starts, fines migrate toward pore throats and either block them or bridge over them, depending on the particle size. The severity of the resulting permeability impairment varies with the fines concentration in the reservoir rocks. Factors that enhance drilling fluid invasion include:

- high permeability of the mud filter cake, a result of either poor design of the drilling fluid or detrimental drilling procedures;
- high overbalance
- long formation-to-drilling fluid contact time.

Water-base mud filtrates may have a low salinity and high pH and may contain dispersants and polymers. Water is a cause of in-situ clay disturbance and of water blocking in low-permeability rocks Dispersants can either aggravate clay problems or precipitate inside pores. Polymers stable at circulating temperatures, but already potentially damaging, can decompose and form residues when submitted to static reservoir temperatures for long periods of time. High-salinity water-base muds generate filtrates that can react with formation brines and precipitate various types of scale.

Filtrate temperature is less than reservoir temperature thus cause cooling effect. It may cause deposition of paraffin or asphaltene. Numerous drawbacks of water based mud led to the development of oil based mud. It is recognised that oil base mud is also damaging to formation . Problems of oil base mud are less numerous than wate r based mud but they are often much more severe. Problems of oil base mud are as follows-

- Oil-base muds contain more solids than water-based mud. Consequently, particle invasion is pronounced.
- Oil that invades gas reservoirs, especially tight reservoir,causes sharp reductions in relative gas permeability (more problematic than water invasion because oil

comparatively higher viscosity and lower vapor pressure of oil).

- Strong oil-wetting surfactants used to disperse solids in oil-base muds convert formation rocks into an wet state. This significantly reduces the, relative permeability to oil.

Cementing Damage

Objective of cementing operation is to achieve perfect isolation between zones by sealing the annulus with a hard, compact, impermeable cement sheath. For efficient cementing operation complete mud removal is essential and washers and spacers, casing movement and turbulent flow is very effective for this purpose.

During mud removal process mudcake can be partially destroyed, and if these cement preflush fluids do not possess the right fluid-loss properties, formation rocks may be less protected against filtrate invasion. This invasion may be increased when high pressure differentials are set (cementing under turbulent flow)

Washers and spacers always contain large amounts of dispersants to suspend and carry mud particles and cake debris. Invasion of clayey formations by these fluids causes additional problems of in-situ clay migration and/or dispersion

The duration of a cementing job is short compared to drilling job thus invasion is less as compared to drilling fluid. It does not mean that fluid loss is neglected. It may result in job failure by either complete loss of the preflush fluids (insufficient volumes) and subsequent contamination (and strong gelling) of the cement slurry by the drilling fluid or by de-hydration of the cement slurry itself.

Cement Slurries

Use of filtrate loss agents and broad particle size distribution of cement grains limited the filtrate invasion of cement slurry. In few cases,it may cause permeability impairment which are as follows-

- The relatively high pH of cement slurry filtrates is particularly detrimental to formation clay minerals. Calcium ions liberated by cement particles are very quickly exchanged on clays near the wellbore. The resulting modification of the filtrate composition makes it a perfect destabilizing fluid in terms of dispersing ability.
- Cement filtrate which comes into contact with connate brines that contain high concentrations of calcium can provoke precipitations of calcium carbonate, lime, or calcium silicate hydrate.
- Over dispersed slurries (with no yield value) present rapid separation of cement particles at the bottom and of water at the top of the cement column. Large invasion of free water is likely to take place in this case. The resulting water blockage may be significant.

Squeeze Cementing

Squeeze cementing is said to be particularly damaging in unconsolidated, high-permeability sandstones. High pressures used for squeezing cement are thought to cause formation fracturing and slurry invasion.

Perforation Damage

Perforating is always a cause of additional damage in formation rocks. Whether it is performed overbalanced or underbalanced, it always compacts the rock around the perforations and produces a zone with an average thickness of 0.5 in. (1 cm) where the permeability reduction averages 80%.

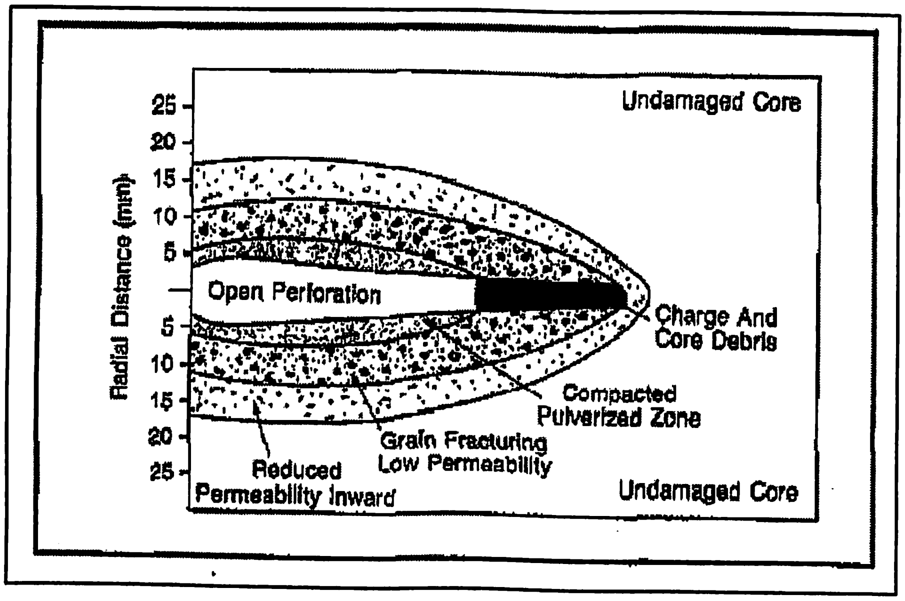


Fig 3.1- Schematic diagram of perforated core showing zones of damage.

There are many other factors that can further reduce productivity.

- Perforating overbalanced always forces formation and gun debris into perforation walls and decreases the permeability near the perforations.
- Perforating overbalanced in fluids that contain particles produces a similar effect and also builds a dense, impermeable cake on the perforation walls.
- Insufficient perforation penetration that has not bypassed drilling damage. Penetration decreases with formation effective stress.
- Improper choice of perforation geometry as it relates to formation type;- large-diameter, low-penetration perforations are preferred in soft rocks that should be gravel packed; low-diameter,

high-penetration ones are preferred in hard formations.

- Incorrect estimate of underbalance pressure required to achieve damage-free perforations. Insufficient pressure differences limit damage removal. Excessive differences lead to sand influx in the wellbore.

Completion And Workover Fluids Damage

Various completion and workover operation is also responsible for formation damage

- Permeability impairment of formation rocks and productivity impairment of perforations by suspended solids (including bacteria) and polymer residues.
- Common problems resulting from filtrate invasion: clay swelling and dispersion, water and emulsion blocks, precipitation of scales.

In order to counter the problems caused during completion and workover operation, clean filtered working fluids should be used. In addition to clean drilling fluid, appropriate technique should be adopted to place these fluids without polluting them with various particulate or gum like materials.

In depleted reservoir, there is strong need to use fluid loss control agents and additives. Specially, for depleted reservoir, foams gases or mists should be used as completion fluid.

Workover brines (especially high-density ones) usually require inhibitors to control corrosion. These products can contribute to emulsion-blockage problems through wettability modification of formation minerals and some times promote iron precipitation in the reservoir.

Damage In Gravel Packs

Main source of damage in gravel packs include-

- Improper placement of the gravel pack (perforations remaining empty or incomplete filling ofthe annulus between casing and screen), allowing perforation filling by formation sand, pack fluidization, and subsequent intermixing of sand and gravel in the case of pressure surges.
- Gravel pack polluted by formation particles duringplacement as a result of incomplete perforation cleaning, or polluted by unbroken gels.
- Thread dope, paint, rust, polymer residues forced between formation sand and gravel pack during placement.
- Inadequate gravel size, leading to gravel-pack invasion by formation fines during production.
- Screens with slots too large (that do not retain gravel) [81] or with slots too narrow that become plugged and reduce production.

Damage During Production

Some reservoirs cannot be produced at high flow rates or large drawdowns without being affected by adverse phenomena. Permanent damage, which cannot be removed simply by reducing production rate, may be created.

Native silts and clays loosely attached to pore walls can be put into motion by high flow rates especially when two or more immiscible fluids are produced at the same time. These particle can either block pore throats in the vicinity of initial location or either migrate toward well bore.

Bridging is less damaging than blockingbecause short period of reverse flow may mechanically disperse the bridge. It cannot be achieved when bridging agglomerates have been previously cemented by precipitates (asphaltenes or scales) or chemically stabilized through the injection of flocculants (such as clay stabilizers).

Excessive drawdown may decrease the pore pressure near the wellbore to such an extent that the effective stress exceeds the formation rock compressive strength. Such a phenomenon is obvious in poorly cemented sandstones where wellbore filling by formation sand is progressive. It is less apparent in chalks where formation compaction and dramatic porosity reduction affect the near-wellbore region without any occurrence of formation.

Reduction in pore pressure during production, and sometimes cooling resulting from gas expansion, results in precipitation of organic] or inorganic materials. Most of the time, such deposits affect only the production string and surface equipment. However, there are cases where they can reduce the formation permeability. Seeds, such as high specific area clays, promote the deposition of organic materials (especially asphaltenes)] or the precipitation of supersaturated salt solutions. Common scales are calcium carbonate] and calcium sulfate . Some problems associated with the deposition of elemental sulfur and of sodium chloride] have also been recognized.

Asphaltene deposition on pore walls may not significantly decrease the formation porosity and absolute permeability. However, through this process, the rock tends to become oil wet, which reduces the relative permeability to oil and, under certain conditions, favours the buildup of emulsion blocks if water is simultaneously produced.

Excessive drawdown in gas condensate reservoirs leads to a bottomhole flowing pressure below the dewpoint. An in-situ distillation occurs with light fractions produced while heavier hydrocarbons remain in the formation and cause a decrease of the relative gas permeability.

Damage during Stimulation

Wellbore Cleanup

When wells are cleaned to remove deposits or corrosion products from production tubing, high concentrations of damaging materials may invade the pay zone. Extreme care should be devoted to prevent these suspensions from being forced into the porous medium. Particularly compounds which are insoluble to cleaning flud is most dangerous as they cannot form impermeable cakes which prevent formation invasion. Rust in acid or paraffin in hot oil are the two most typical redissolved wellbore compounds. They will reprecipitate in the formation and cause extensive severe and permanent damage.

Acidizing Treatments

Usual problems already encountered in other phases of the life of a well may also occur during acidizing treatments, especially in cases of inappropriate design. These include:

- Damaging materials from the tubing entering the formation rock.
- Oil-wetting the reservoir by surfactants, especially corrosion inhibitors [112], which can create emulsion blocks.
- Water blocks
- Asphaltene/paraffin deposition when large volumes of acid are injected.

In addition to these common damaging processes, specific production impairment can also possible from poor design of acidizing treatments. These impairments include the following:

- Sludges produced by reaction between acids and asphaltenes especially in the presence of some additives (particularly surfactants) or of dissolved iron .
- Deconsolidation of formation rock caused by excessive dissolution of cementing materials by acids.

- Precipitation of byproducts from the reaction of acids with formation minerals.It can be predicted with help of geochemical models which depends on formation rock and treatment fluid compositions pressure, temperature, and contact time. However, these models cannot predict the damaging potential of these products because they do not include any physical description of the way they are precipitated. Hydrated silica may precipitate on clay surfaces and is not necessarily damaging. Compounds such as borosilicate and fluoborates can even be beneficial. On the other hand, gelatinous precipitates, such as ferric hydroxide, can completely plug pores and can be particularly difficult to remove]. A third class of byproducts consists of species such as fluosilicates precipitating in the form of individual crystals that can migrate toward pore throats and produce a "log-jam." Iron sulfide that precipitates, even at very low pH during the acidization of sour wells, is another compound belonging to this category.

- Some sequestering agents added to acids to prevent iron problems can form precipitates when the acid is spent and no iron is present.

- Permeability impairment by residues present in corrosion inhibitors or produced through thermal degradation of polymers, such as friction reducers.

Water Control Treatments

Water cuts in production well reduces oil and gas production. It can be reduced by the injection of polyacrylamides. Apart from causes inherent to the technique (mechanical, chemical, or thermal degradation of the polymer), some failures can be attributed to formation damage induced by the treatment -

- Formation damage from incompletely dissolved polymer.
- Formation damage from crosslinked gels.
- Unfiltered base water.
- Water blocks.
- Interaction of water or polyacrylamide with formation clays, even in oil-bearing zones.

Specific Problems In Injection Wells

Water Injectors

Most problems already cited can also occur in water injection wells . Several papers have been published on particular aspects related to damage from water injection:

- Scales formed from mixing incompatible injection and formation waters, or as a result of the presence of carbon dioxide or hydrogen sulfide in the reservoir, or by ionic strength increase of the injected water through the dissolution of formation minerals (these precipitates are more difficult to remove in injectors because they build up far from the wellbore, as a result of temperature increase or pressure decrease);
- Colloid plugging, especially by ferric species produced by tubing corrosion when there is oxygen in the injected water.
- Plugging by bacterial residues is also developed in water injection wells

Alkaline and Steam Flooding

Problems associated with these types of flooding stem from the dissolution of siliceous formation minerals by high-pH fluids or high-temperature steam condensates.This dissolution can cause poorly consolidated sandstones to collapse or silica to reprecipitate at distances from the wellbore where the alkalinity and/or the temperature of the floods have decreased. Some free-moving, damaging zeolites are formed even at high pH and in hot environments through the chemical attack of certain clay minerals (kaolinite and montmorillonite) Particular types of scale may also be precipitated during alkaline flooding, such as calcium carbonate, magnesium silicate, and amorphous silica.

Carbon Dioxide Flooding

Problems specific to the injection of C02 in a well include:

- Precipitation of organic materials upon contact of C02 with oil-in-place (special type of sludge).
- Precipitation of particular scales, such as barium sulfate from acidic conditions or iron carbonate from me combination of C02 with corrosion-produced iron.
- Dissolution of carbonate minerals and subsequent porosity alteration .

Polymer Flooding

Additional causes of formation damage, specifically related to injection of polymers into the rock matrix, include:

- Plugging by gel residues.
- Dislodging and migration of formation fines by pseudo-plastic fluids .

Methods to enhance productivity ratio

Various methods are adopted to increase productivity ratio of well. These methods are as follows-

Acidization

Acidization is the process in which acid is injected into the formation , below fracturing pressure. Objective of acidization is dissolution of minerals present in the form of matrix as well as fines which clog pore throats. Consequently, permeability of formation increases.Successful acidizing involves strategic implementation. It requires detail study of formation mineralogy, compatibility of acid, additives with formation fluid and formation rock. Generally, 15wt% HCl is used for limestone formation and mixture of 12wt% HCL and 3wt%HF is used for sandstone formation.

A variety of acid additives helps the acid work more efficiently, corrosion inhibitors are used to prevent acid attacking the steel tubing and casing at high bottomhole temperature, retarders reduces quick spending on formation rock.

Acid Fracturing

Acid fracturing is well stimulation process in which acid is injected into a formation at pressure sufficient to fracture the formation or to open the existing natural fractures. As acid flows along the fracture it etches the face of formation in non-uniform manner. Consequently conductive fracture is created which remains open even after fracture closes, resulting in increment in formation permeability.

Hydraulic Fracturing

It is the process which is applied to influence large area of reservoir. In hydraulic fracturing process, properly tailored fracture fluid is injected at pressure which create fracture in strata. Certain pressure is maintained to propagate the fracture into formation.

In order to keep fracture open even after removal of pressure, propping agent is added into fracturing fluids. Sand grains, Glass beads etc are some example of proppants.

Hydraulic fracturing is very expensive operation as a result every possible step is taken to make job efficient and successful.

In addition to acidization, acid fracturing and hydraulic fracturing, certain solvents,surfactants, chemical agents are also injected into formation. Application of any foreign substance into reservoir to increase productivity ratio depends upon type of damage. Some examples of damage and their solution are as follows-

Emulsions

Intermixing of oil and water based fluids in the formation lead to formation of emulsion.Emulsions are stabilized by surface-active materials (surfactants) and foreign or native fines. Generally, mutual solvents, with or without de-emulsifiers, are used for treating such problems.

Wettability Change

Wettability of formation may alter from water to oil due to adsorption of surface active minerals from oil base drilling, workover, completion fluids on the rock. It is removed by injecting (mutual) solvents to remove the oil-wetting hydrocarbon phase and then injecting strongly water-wetting surfactants.. The oil phase, which is often precipitated asphaltenes or paraffins and is responsible for oil wetting too, has to be removed first with a solvent.

Water Block

Water block may form due to increase in water saturation near well bore due to increase in water saturation. Water block may form during completion operation due to water based filtrate invasion and production due to water conning. Alcohols are added to reduce surface tension between water and oil or gas.

Scales

Scales are precipitated mineral deposit.. They can precipitate in the tubing, in the perforations, and/or in the formation. Scale deposition occurs during production because of the lower temperatures and pressures encountered in or near the wellbore. Scales can also form when incompatible waters mix: formation water and either a fluid filtrate or injection water.Carbonate scale and sulfate scale are most common type of scale. Various solvents like HCL, EDTA etc are injected to dissolve scales. Contact time is a very important factor in the design of a scale-removal treatment. Sufficient time is allowed for acid to reach and effectively dissolve bulk of the scale material.

Organic Deposits

Organic deposits are asphaltenes and parrafins which get deposited into tubing , perforation and formation. It happens due to change in temperature and pressure near the well bore region. Organic deposits must not be confused with another type of deposit called sludge. This deposit is produced by a reaction between certain crude oils and strong inorganic acids. Sludges cannot be dissolved. Organic deposits can be resolubilized by organic solvents.

Mixed Deposits

Mixed organic/inorganic deposits are a blend of organic compounds and either scales or silts and clays. When migrating, fines associated with an increase in water production in a sandstone reservoir become oil wet, and they act as a nucleation site for organic deposits.Such type of deposition requires dual- solvent system such as dispersants of hydrocarbon(aromatics) solvent into acid.

Silts And Clays

Damage from silts and clays includes the invasion of the reservoir permeability by drilling mud and the swelling and/or migration of reservoir fines. Damage from fines is located in the near-wellbore area within a 3- to 5-ft (1- to 1.5-m) radius. Damage may also occur in a gravel pack In sandstones it is removed by treatment with an acid containing HF (mud acid of various strengths or in combination with organic acids or fluoboric acid and its similar variations).in carbonates it is removed by hydrochloric acid.

Chapter 4 *Acidization*

Sandstone Acidization

An acidizing treatment for a sandstone formation normally will consist of sequentially injecting three fluids: a preflush, the hydrofluoric acid-hydrochloric acid mixture (HF-HCI mixture), and an afterflush. Each of these fluids serves a definite purpose.

The preflush is usually HC1 ranging in concentration from 5-15 wt% and containing corrosion inhibitors and other additives, as required. The preflush displaces connate water from the near-wellbore region, thereby minimizing direct contact between sodium and potassium ions in the formation brine and the HF or fluosilicate reaction products. Normally, this will reduce the possible reda-maging of the formation by precipitation of insoluble sodium or potassium fluorides or fluosilicates. The HCI preflush also reacts with calcite or other calcareous materials, thereby reducing (or eliminating) reaction between HF and CaC03. This avoids waste of the more expensive HF and prevents precipitation of calcium fluoride (CaF2). Finally, the preflush may serve to precool the formation.

Following the preflush, an HF-HCI mixture (usually 3 wt% HF and 12 wt% HCI) is then injected. The HF reacts with clays, sand, drilling mud, or cement to improve permeability near the wellbore. The HCI will not react with these materials but is needed to keep the pH low, thereby reducing the precipitation of HF reaction products.

An afterflush is generally applied to isolate the reacted HF from brine that may be used to flush the tubing, to displace spent acid into the formation, and to restore water wettability of the formation. Normally, one of three types of afterflush is used: (1) for oil wells, either a hydrocarbon afterflush, such as diesel oil or 15 wt% HCl is used; (2) for water injection wells, HCl is used; and (3) for gas wells, either acid or a gas (such as nitrogen or natural gas) is used. With a liquid afterflush chemicals are usually added to aid in removing treating fluids from the formation, restoring water wettability to formation solids and removing precipitated acid reaction products, and prevention of emulsion formation. When a gas is used as an afterflush, cleanup additives such as surfactants to reduce the surface tension are sometimes added to the HF-HC1 stage of the treatment

Sandstone Matrix Acidizing Theory

Matrix acidizing is that process whereby acid is injected into a formation at pressures less than the fracture pressure. The acid is forced into the formation pores in the region surrounding the wellbore. Rock will consequently be dissolved in the invaded region, leaving permeable channels leading into the wellbore to assist the production of oil. This well treatment is normally applied to remove near-wellbore damage.

Three important mechanisms that contribute to the final productivity of an acidized well include: erosion of the pore structure as the acid flows through these pores, consumption of the acid, and selective dissolution of certain minerals. Erosion of the pore structure leads to both increased porosity and permeability. Rate of acid consumption is an important feature, since this limits the depth to which acid penetrates. Finally, the mineral composition in the acidized region depends both on time and distance from the wellbore face because minerals do react with acid at differing rate. These mechanisms are coupled together. It is not possible to consider them separately. It can be explained in mathematical form using acid balance in porous media.

Lumped Reaction Model

According to lumped reaction model all of acid soluble minerals are divided into two categories-fast reacting and slow reaction. Detrital quartz, Detrital Clay,Chert come under slow reacting minerals and Authogenic Clays, Detrital Feldspar and Amorphous Silica comes under fast reacting minerals. An approximate analytical solution of acid mass balance equation is possible if the rate of reaction of slow reacting minerals is much less than fast reacting minerals so that only fast reaction is considered,resulting equation as follows-

$$-u\frac{\partial c_{HF}}{\partial x} - (1-\phi_0)V_F\alpha_F E_f^{(F)} c_{HF} = \phi_0\frac{\partial c_{HF}}{\partial t}$$

----------------------------------(4.1)

The following dimensionless variables can now be defined:

$\psi = c_{HF}/c^0_{HF}$

$\Lambda = V_F/V^0_F$

$\epsilon = x/L$

$\theta = t/\tau = tu/\phi_0 L$

where L is the length of a linear core and θ is the number of pore volumes injected into the core. Here C^0_{HF} and V^0_F are the initial values of c_{HF} and V_F, respectively. The above equation can be written in terms of these new variables as

$$\frac{\partial\psi}{\partial\theta} + \frac{\partial\psi}{\partial\epsilon} + \left[\frac{(1-\phi_0)V^0_F E_f^{(F)}\alpha_F L}{u}\right]\psi\Lambda = 0$$

....................................(4.2)

$$\frac{\partial \Lambda}{\partial \theta} = -\left(\frac{\phi_0 \beta_F c^0_{HF} M_F}{V^0_F \rho_F}\right)\left(\frac{V^0_F E_f^{(F)} \alpha_F L}{u}\right)\psi\Lambda$$

--------------------(4.3)

There are two dimensionless parameters appearing in these equation. The Damkohler number is defined as

$$D_a^{(F)} = \frac{(1 - \phi_0) V^0_F E^F_f \alpha_F L}{u}$$

--(4.4)

$$A^{(F)} = \frac{\phi_0 \beta_F c^0_{HF} M}{(1 - \phi_0) V^0_F}$$

---(4.5)

Damkohler number= (Rate at which acid is consumed by fast reacting minerals)/ (Rate at which acid is transported by convection).

Acid capacity number= (Mass of minerals dissolved per unit volume)/ (Mass of minerals present per unit volume)

Empirical relation for determination of permeability

Labrid proposed an equation

$$\frac{k}{k_0} = M\left(\frac{\phi}{\phi_0}\right)^n$$

---(4.6)

where the constants M and n were determined to be 1 and 3, respectively, for a Fontainbleau sandstone. These values are comparable to those found in theory by Guin and Schechter. However, in sandstones that are less homogeneous, n is found to be larger than 3.

Lund and Fogler have fitted data reported by McCune et al. obtained by acidizing a Phacoides sandstone and found the empirical equation

$$k/k_0 = \exp\left[M\left(\frac{\phi - \phi_0}{\Delta\phi_{max}}\right)\right]$$

---(4.7) where M = 1.5 and $\Delta\phi$max = 0.08 gave the best fit for that particular sandstone. A similar expression has been used by Walsh et al. based on extensive core studies reported by Lambert. Walsh et al. found M/$\Delta\phi$max = 45.7.

It is important to recognize that the relationship between k/k_o and($\Delta\phi=\phi-\phi o$) strongly depends on the change in the density of the larger pores and this must vary from sandstone to sandstone. The more homogeneous sandstones composed almost entirely of well-sorted sand grains will not yield values of M/ $\Delta\phi$max as large as the more heterogeneous ones. Thus, it is normally necessary to have experimental data from core samples of the formation to be treated if an accurate expression for the permeability is required. It will, however, be observed that generally an accurate relationship may not be required. The important fact is that M/ $\Delta\phi$max max is often a large number. Small increases in the porosity will lead to large increases in permeability. Thus it becomes most crucial to evaluate the porosity increase, or equivalently, to estimate the depth to which live acid penetrates.

Permeability of acidized zone

Approach that has been used in the design of acidization job is based on the empirical equations that has been derived by experiments on very porous material like sintered glass, Berea sandstone etc. Once the damage is removed, then there is further increases in permeability. Thus, it is important to establish the zone in which damage in the form of particles clogging the pore throats has been cleared. Here we assume that damage removal is accomplished for all $\varepsilon < \varepsilon_f$, where ε_f is the frontal position. The zone behind the front has a permeability k_A (the A denotes *acidized)*, whereas downstream of the front the permeability is K_s . The average permeability in core is gven by

$$\frac{\bar{k}(\theta)}{k_S} = \frac{1}{\int_0^1 \frac{k_S\, d\epsilon}{k}} = \frac{k_A}{\epsilon_f k_S + (1 - \epsilon_f) k_A} \qquad (\text{for } \epsilon_f < 1)$$

------------------------------(4.8)

The mean permeability *(k)*, which is the average value obtained by measuring the pressure drop across the entire length of the core, depends on the position of the front. Upstream from the front, the fast-reacting minerals have been removed. The porosity has been increased by virtue of their removal. Since *V%* is the volume of fast-reacting minerals per unit volume of minerals, the increase in porosity is given by

$$\Delta\phi = \phi - \phi_0 = V_F^0(1 - \phi_0)$$

--(4.9)

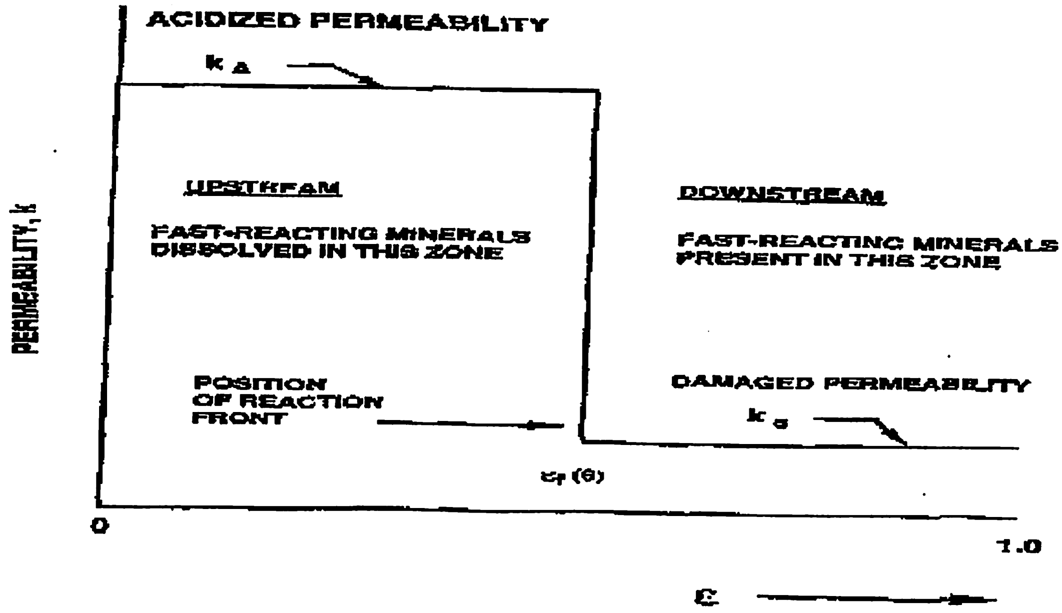


Figure 4.1 Figure showing permeability as function of position in linear system

Characteristics of the Slow Reaction Zone

The general features governing the design of a matrix acidizing treatment can best be visualized by first considering the penetration of acid into a core whose solid matrix is composed entirely of a slow-reacting substance, say, quartz. Since the volume of the slow reacting solid is large, then the acid capacity number of the slow reacting quart (A_c^s) tends to zero. It is observed that in the limit of small acid capacity numbers.

$$\psi = \exp(-D_a^{(S)}\varepsilon) \qquad \text{--(4.10)}$$

This equation is interesting since it suggests that the acid concentration depends on the distance measured from the core inlet, but does not depend on θ, the number of PV injected. This implies that the effluent concentration from a core should be constant once the fast-reacting minerals have been removed as shown in Figure 4.2 and Figure 4.3. The second segment is practically horizontal indicating that for this particular Berea sample the effluent concentration becomes essentially constant, independent of θ once the fast-reacting materials have been removed. A number of experiments on Berea all show similar behavior.

We expect that acidization carried out in the field will exhibit similar behavior. Thus, it is worthwhile to investigate the implications of equation 4.10 in somewhat greater detail.

If it is desired to increase the acid penetration distance, the Damkohler number for the slow-reacting minerals must be reduced. The only variables that are available to the experimenter are the temperature, the acid concentration, and the acid flux. In order to reduce Damkohler number core temperature can be reduced using adequate preflush volume. Consequently, acid penetration distance increases.

The Damkohler number is independent of the inlet acid concentration, so that increasing it will not change the position at which ψ takes on a particular value. Of course for fixed ψ, the acid concentration increases as the inlet acid concentration increases.There are variety of reasonsfor which increasing the concentration of HF in excess of some minimum level may be undesirable.

The Damkohler number can also be decreased by increasing the acid flux. In core tests u can be varied over a wide range; however, in matrix acid treatments the acid flux is limited by the fracture gradient.

Equation (4.5) is a key result for the design of matrix acid treatments. It shows that there is a limit to the depth surrounding the wellbore from which damage can be removed by acid

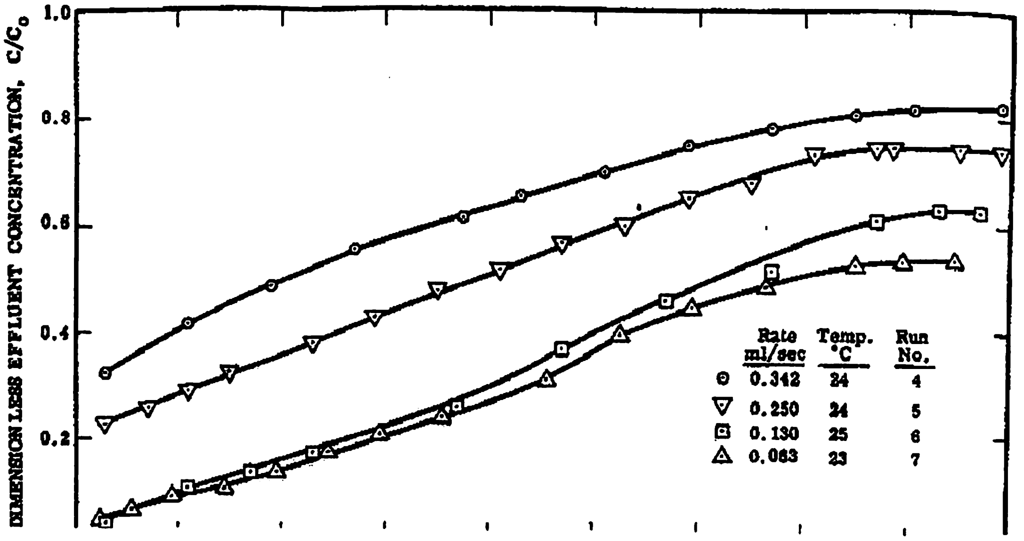


Figure 4.2Plotted data of effluent acid concentration as a function of PV injected for Berea Sandstone . The various curves show the effect of the flow rate.

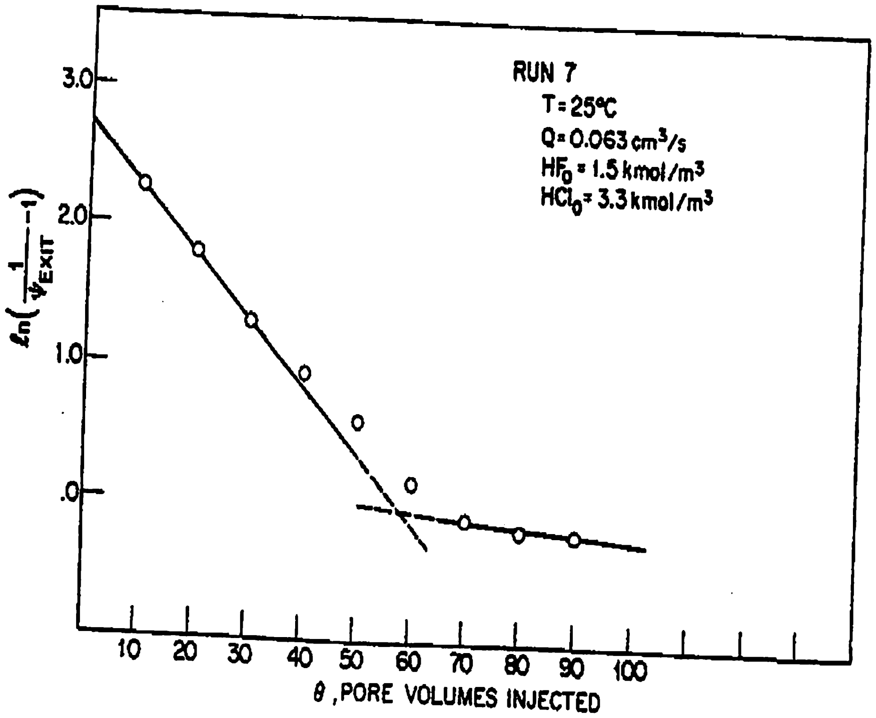


Figure 4.3 The effluent HF acid concentration for an injection rate of 0.063 cm^3/s replotted from Fig.4.2 to show the two reaction zones (With permission of American Institute of Chemical Engineers.)

Speed of the Fast-Reacting Mineral Front

Effluent acid concentration in two extreme cases—one for which the system contains only a small quantity of fast-reacting mineral with the remainder of the solid matrix being composed of an inert solid, and at the other extreme, one which is composed entirely of a single slow-reacting mineral have been discused. In practice, of course, both types of minerals will be present and one must, at a minimum, take into account the presence of both since they interact with one another. This interaction is illustrated by the curves shown in Fig. 4.4 The fast-reacting mineral is shown to exhibit a reaction front shaped much the same as that shown in Fig. 4.5 where there is no slow-reacting mineral. The difference between the reacting zones shown in Figs. 4.4 and 4.5 is in the acid concentration. Because of the presence of a large quantity of the slow-reacting mineral, the acid concentration decreases continuously from the core inlet until it reaches the reaction zone where quantities of fast-reacting mineral remain. At this point, the acid concentration decreases rapidly causing the fast-reacting front to advance.

Let us define ε_f as the position of the reaction front and consider the rate at which this front moves. We know, of course, that as ε_f increases, the concentration of acid arriving at the front will decrease in accordance with Eq. (4.10). the acid concentration decreases at the front, the velocity of the front will also decrease since the dissolving power of the acid is directly proportional to the acid concentration. Thus because the acid must flow through a porous medium of slow-reacting mineral to reach the reaction front, a portion of the acid dissolving power of the acid is lost. Clearly, a fast-reacting mineral cannot be removed for a distance beyond the acid penetration distance. This is a key concept that will be applied in the design of an acid treatment.

To complete those concepts needed for a rational design, the frontal position (ε_f) as a function of the PV injected must now be calculated.

To do this calculation it is noted the front moves at a rate dictated by the acid capacity number. To account for the reduced acid concentration as the acid arrives at the front as shown by Fig. 4.4, the acid capacity number at the front becomes a function of the frontal position. Thus,

$$\frac{\phi_0 v_f^{II}}{u} = \frac{d\epsilon_f}{d\theta} = \frac{a_c^{(F)}(\epsilon_f)}{1 + a_c^{(F)}(\epsilon_f)} \qquad \text{-----------------(4.11)}$$

where a_c is the acid capacity number evaluated at the reaction front. It is clearly less than the acid capacity number of the injected fluid, Ac^f since, as observed in Fig 4.4 the acid concentration at the front is less than that injected. From equation (4.10)

$$a_c^{(F)}(\epsilon_f) = A_c^{(F)}\cdot\psi = A_c^{(F)}\exp(-D_a^{(S)}\epsilon_f) \qquad \text{-------------------------------(4.12)}$$

Substituting Ea. (4.12)into Ea. (4.13) and integrating gives

$$\theta = \frac{\exp(D_a^{(S)}\epsilon_f) - 1}{A_c^{(F)}D_a^{(S)}} + \epsilon_f \qquad \text{-------------------------------(4.13)}$$

This expression is the desired one. It relates the number of PV injected to the position of the front. There are two parameters that appear, the Damkohler number for the slow reacting mineral. The damkohler number for the fast reaction is a third important variable. If it is sufficiently large , it is possible to assume the front to be sharp. The acid capacity number for slow reacting mineral is small ((A_c^s) tends to zero and is not needed in the designof an acid treatment. Equation (4.13) can be used to calculate A_c given Damkohler and the point of intersection between the two line segments in Fig. 4.3. At this intersection it can be aassumed that $e_f = 1$, i.e., this is the number of PV θ, at which the front emerges from the core.

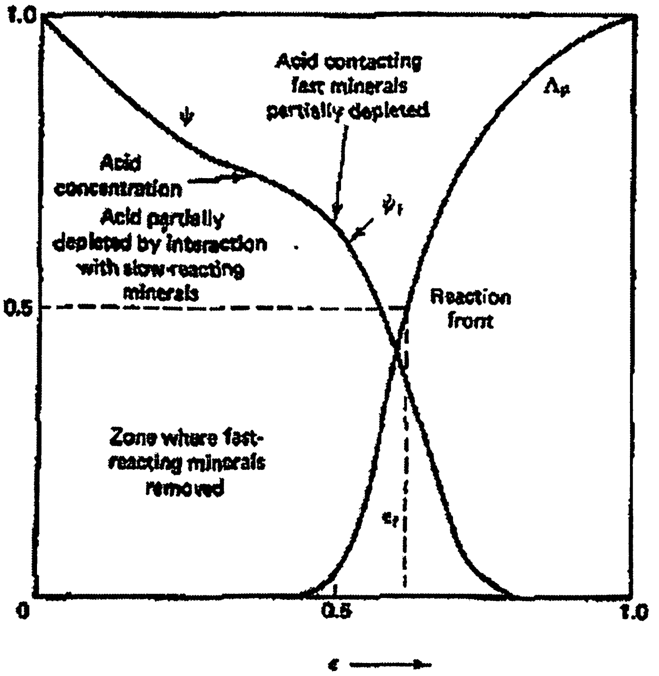


Fig 4.4 Graph showing interactionof two mineral front.The acid concentration is plotted as function of position for the case of fast reacting minerals and slow reacting minerals.

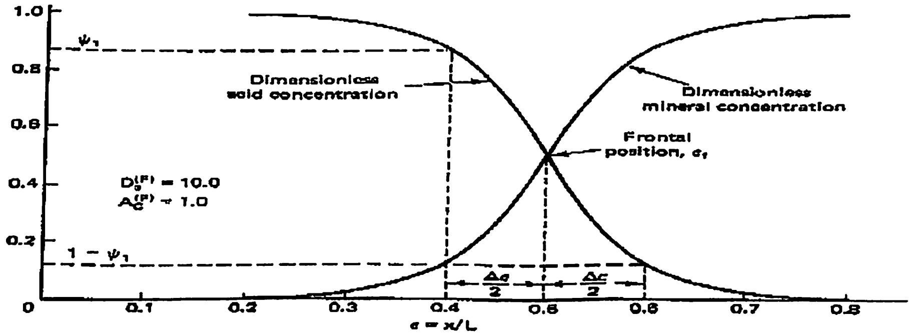


Fig 4.5 Detail structure of the reaction zone shown for single fast reaction

Carbonate Acidization

The mechanism of acid attack on carbonates is quite different from that of sandstones, the rate of acid reaction with carbonates is much faster than with most minerals constituting sandstones. The difference in acid reaction rate produces a profound change in the mechanism of acid attack on carbonates.

Acid Channeling In Carbonates: Wormholes

Sedimentary rocks are often composed of interconnected pores having a wide range of different sizes. More acid tends to flow through the larger pores than through the smaller ones. If the acid reaction rate is very fast, then a significant proportion of the acid entering both the larger pores and the smaller pores will react. However, since the larger pores receive more acid, they tend to enlarge at a faster rate causing even more acid to enter the pore. Thus, larger pores enlarge more rapidly than smaller ones. This unstable process tends to produce a single larger pore extending from the inlet face of a core of reservoir rocks to the outlet face. This large channel, which accepts virtually all of the acid, is known as a wormhole.

Wormhole formation occurs when larger pores tend to grow in cross sectional area at a rate much larger than the growth rate of smaller pores.The condition for wormhole growth can be made definate if the rate of change of pore area (A) with time (t) can be made definate in the form of

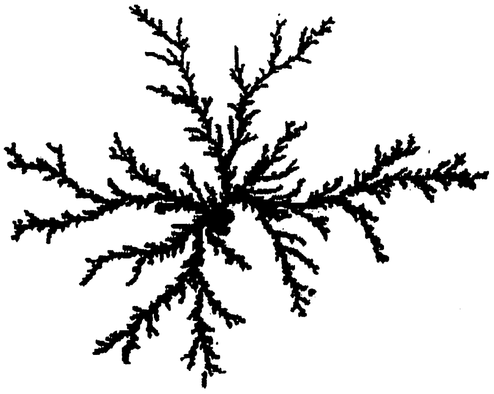
$$\frac{dA}{dt} = \Psi A^{1-n} \quad \text{...(4.14)}$$

Here Ψ depends on rection rate constant and the acid diffusion constant but not on pore area.The equation can be further integrated in the form of

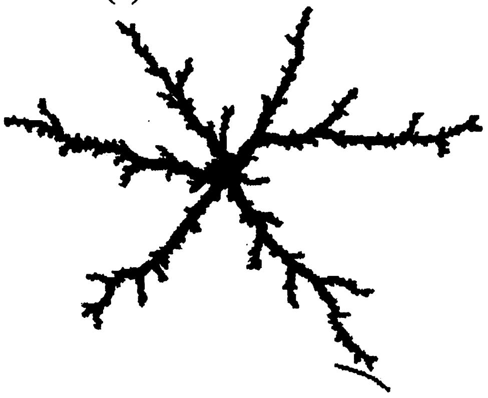
$$A = (A_0^n + n\Psi t)^{1/n} \quad \text{...(4.15)}$$

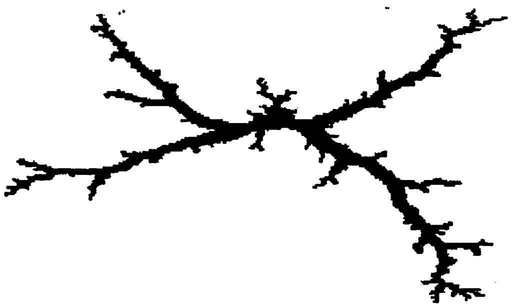
For n > 0 smaller pores tend to approach the same ultimate size as the larger pores.If n<0 the larger pores tend to grow much larger than the smaller ones. Between the limits of fast and slow reaction rates the tendency for severe channeling appears gradually. The tendency to form wormholes depends both on the acid reaction rate as the flow rate, at high flow rates the system will behave as the reaction rate is small. The influence of flow rate on wormhole formations has been studied by Daccord; he conducted experiments by dissolving calcium sulphate in water.

The flow is stopped after four hours using (a) 48 (b) 6 (c) 2 cm3/hr respectively. The experiments indicated decreased tendency to form wormholes as the fluid velocity is increased.



(a)





(c)

Fig 4.6 Typical wormhole patterns created in a radial flow geometry. The flow is stopped after 4 hours using three different injection rates.

Fluid Loss From Circular Pores

The fluid loss taking place from a growing wormhole may still be reactive and that is the reason for a tree like appearance of a wormhole, to model the correct length of wormholes this fluid loss has to be determined. To couple all mass transfer and hydrodynamic effects together to develop wormhole geometry as a function of time is a complex technique. For high fluid loss rates acid diffusion can be neglected as acid is transported to the rock surface primarily by convection. Considering circular wormholes of a fixed radius and length, based on the injected acid volume and acid dissolving power, wormhole geometry can be modeled. But these models fail when diffusion provides a significant acid flux to the pore walls.

Matrix Treatment for Carbonates

Hydrochloric acid reacts rapidly when contacted with either calcite or dolomite, a number of patents have been issued disclosing methods for reducing the reaction rate so as to reduce the tendency for wormhole formation. The proposed techniques can be divided into two general classifications:

1. One classification includes techniques that involve the injection of chemicals (not acids) that react slowly, but at a controlled rate to produce an acid. The acid product will then react rapidly with carbonates. These processes limit the reaction rate by producing in-situ acid at a controlled rate. They may have the further advantage of reducing corrosion problems whenever the chemicals from which the acid is derived are less corrosive than acid.
2. A second classification is represented by methods for retarding the effective acid reaction rate. This can be accomplished by reducing the rate of acid diffusion to the pore walls or by coating the rock surface with a chemical that slows the reaction of the acid with the rock.

Additives

Matrix acidizing is a complex chemical process and therefore it is necessary to include some additional chemicals for achieving the objective of damage removal with minimizing the side effects. For the same reason it is necessary to include some additives in the required acid solution. Some of the commonly added acid additives are-

- Corrosion inhibitors.
- Surfactants.
- Diverting agents.
- Anti sludge agents.
- Iron controllers.
- Mutual solvents; and
- Clay stabilizers.

These additives are intended to-

- To divert acid flow from more permeable, undamaged zones permeable ones thereby allowing a more uniform treatment.
- To prevent corrosion of wellbore tubular goods.
- To form complexes with iron, to prevent precipitation.
- To reduce friction drop through tubular goods; and
- To eliminate emulsions and sludging in certain highly asphaltic oils.

Corrosion Inhibitors.

The most important acid additives are corrosion inhibitors, if high bottom hole temperatures are encountered or long acid-pipe contact times are anticipated, the choice of the acid itself is governed by the selection of the most economical means for controlling corrosion and still accomplishing the goals established for the treatment.

Any metal surface is composed of electrodes, as long as this metal surface remains dry the electrical circuit remains short circuited but on exposure to acid solution local action cells starts functioning and is accompanied by chemical conversion of metal to corrosion products.

A compound used as inhibitors requires a favorable polar group or a group by which the molecule can attach itself to the metal compound, these includes nitrogen, sulphur, alcohol or an amine compound. Commercially used inhibitors are complex organic compounds.

Factors effecting corrosion during an acid treatment are

- Temperature
- Contact time.
- Acid concentration.
- Metal type; and
- The corrosion inhibitor used.
- Degree of agitation.

- Metal to acid volume ratio.
- Gas composition if an interface is present.
- Pressure.
- Presence of other additives such as surfactants.

These factors are taken into account by laboratory evaluation of metal surface exposed to the corrosion inhibitor to be used in the treatment. The metal coupon is inserted into a heated pressure vessel containing the acid and the corrosion inhibitor to be used, the amount of corrosion is measured by the weighing the metal coupon before and after the test.

Agitation increases the corrosion rate, thus if mass transfer is a limiting factor effect of agitation may be pronounced. At low levels of agitation corrosion rate decreases and at high levels corrosion rate increases, thus it is recommended that oxygen should be excluded from the test bubbling nitrogen through the acid solution.

The effectiveness of a given corrosion inhibitor also depends on the metal and the acid type and for the same reason formic or acetic acid is used in deeper hot wells because it is difficult to inhibit the corrosion of hydrochloric acid at these conditions. Any additive that alters the tendency of corrosion inhibitor to absorb on the metal surface like that of surfactants, mutual solvents also effects its effectiveness in the given acid solution.

Surfactants

Surface active agents are used in acid solution to-

- Demulsify spent acid and oil.
- Reduce interfacial tension.
- Speed cleanup; and
- To prevent sludge formation.

Surfactants should never be added to the acid solutions without the understanding of there effect evaluated at reservoir conditions on live crude. Generally anionic or non-ionic surfactants are preferred for use in acid solution. The surfactant added to the acid solution should not reduce the effectiveness of corrosion inhibitor being used and thus fluorocarbon surfactants may be the best choice concerning this issue provided that it serves other purposes well too.

Diverting Agents.

It is necessary to treat the full productive interval with the acid solution to obtain maximum benefit. When several sands are open to the wellbore it is necessary to divide the treatment into stages. This is done primarily with the use of diverting agents. Diverting agents are small particles that can be added batch wise to the treatment fluid to temporarily plug the selected zones or may be added continuously to the injected fluids, one method of this is the use of ball sealers.

Diverting agents are basically used to bridge across the formation pores and form a filter cake on the sand surface. Chemicals used for diversion include finely ground inert organic resins, solid organic acids, mixture of waxes, oil soluble polymers and mixtures of inert solids with a water soluble polymer.

The primary properties a good diverting material is-

- The material should be essentially insoluble in concentrated acids.
- It should form a dense filter cake of low permeability on the sand face without penetrating into the formation.
- It should not have a high density so that settling in the wellbore is a problem.
- It should be easily removed from the sand face during production.

The materials most often used with acid treatments of oil wells are finely ground organic resins. These materials are sometimes a high molecular weight HC resin that is primarily aliphatic in nature. Such resins exhibit considerable oil solubility and thus it should be removed during production.

The organic resins should consist of a mixture of large particles mixed together with smaller ones. This mixture will permit the formation of a low-permeability filter cake. Use of small particles may permit substantial penetration into the formation, which is, of course, undesirable since the particles may then be difficult to remove following the treatment. On the other hand, particles large enough to bridge at the sand face may not provide a low-permeability filter cake. Thus a compromise between the two has to be designed and used.

Various techniques have been used for achieving better fluid placement over the entire vertical horizon.

Chemical Diverting Techniques

The earliest attempts for fluid diversion were done using a chemical diverting agent, a soap solution that reacted with calcium chloride that form a water insoluble but oil soluble calcium soap. This precipitate acted as a diverting agent for HCL. But in this technique generation of solid precipitate cause potentially permanent damage to the formation, thus it was ruled out. Other systems used cellophane flakes suspended in water gel with a bacteria breaker. A major diversion technique used these days uses completely soluble materials such as wax polymer blends and hydrocarbon resins in production wells or rock salts and benzoic acid in water injection wells.

Mechanical Placement Techniques

- In 1950 development of hydraulically operated inflatable packers led to improved diverting techniques. With the use of these packers as a straddle tool it is possible to treat three productive intervals separately without moving the completions.
- Frac baffles provided more economic completions in multilayered reservoirs. In this method one or more concentric baffle rings were designed to accept a bomb. Bombs of different diameters were dropped to sit on the correct diameter baffle and thus isolate the zone to be treated. Diversion in open hole using interface locator tool.
- Another mechanical placement technique used ball sealers, which were originally introduced in 1956. They are added to the treatment fluid, carried to the perforations and seal the perforation accepting larger quantities of the treatment fluid used. Sufficient rate must be available to maintain a differential pressure across the perforations to keep the balls in place. But this technique is not suitable in wells with large number of perforations. More efficiency can be gained with the use of buoyant ball sealers.

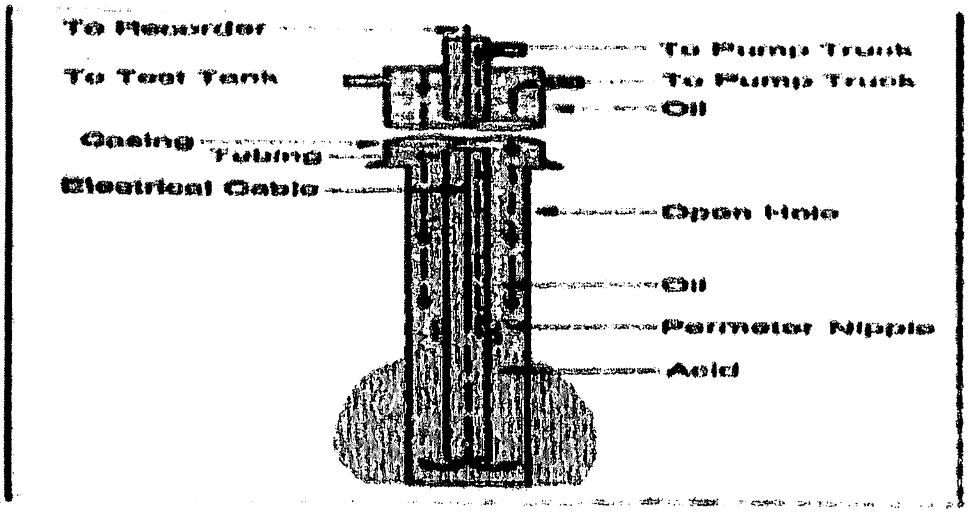


Fig 4.7 Two ball sealer sitting process.

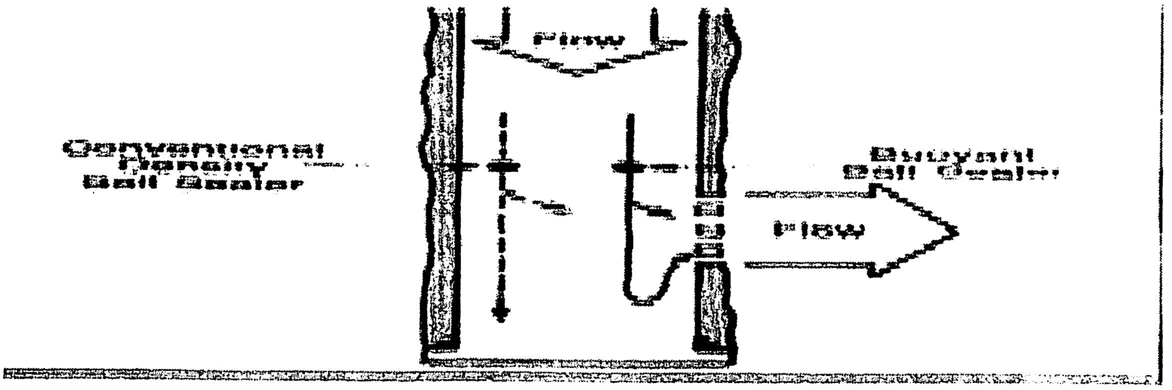


Fig 4.8 Buoyant Ball Sealers

With the use of these mechanical placement techniques required value of fluid cab be injected to each of the zone to be treated, but these techniques are expensive and are time consuming as they require a rig on site at all the time of the treatment.

Anti Sludge Agents

Sludge is basically a precipitate which forms on reaction of high strength acids with crude oil, this sludge blocks the pores and thus effect the ultimate recovery.

Methods of sludge prevention are-

- Solvent (Xylene, Toluene) pre flush to minimize physical contact.
- Use of low strength acids.
- Non-ionic surfactants to minimize precipitation of colloidal suspension.

Iron Controllers

The ferric ions released by mineral dissolution during the acid treatment re precipitate as a gelatinous, damaging ferric hydroxide whenever the pH of the acid solution rises above 2.2. Most of the minerals containing ferric ions will be reacted during the acidization treatment when HF is present but a proper preflush of HCL acid ensures that HF remains un reacted thereby maintaining a low solution pH and precluding the re precipitation of iron in sandstone acidizing treatments.

The precipitation of gelatinous ferric hydroxide can be prevented by adding certain complexing or sequestering agents to the acid. Several organic acids (citric, lactic, acetic and gluconic) and their derivatives ethylene-diaminetetraacetic acid. (EDTA) and nitrilotriacetic acid (NTA) are considered useful sequestering agents.

These acids have been evaluated by Smith et al. They found that each material has certain advantages and limitations. Both cost and performance vary widely. Performance is affected by both temperature and the presence of other metal ions. Only citric acid, EDTA, and NTA can hold as much as 3000 ppm ferric iron in spent acid solutions for more than four hours at temperatures above 50°C. Lactic, acetic, and gluconic acids may prevent ferric hydroxide precipitation from spent acids at lower temperatures and iron concentrations or for shorter periods of time. Lactic acid, in particular, is ineffective at temp. above 80°C. Studies have indicated that several chemicals can be effective complexing agents when used in the correct application. There is no one best agent for all applications.

Mutual Solvents

Acid corrosion inhibitors provide protection by adsorbing on metal surfaces. Upon entering the formation, the inhibitor is often strongly adsorbed on clays and other minerals especially as the acid pH increases. In some cases corrosion inhibitors contain acid-insoluble residues that can cause plugging on the face of the formation and also that inhibitor adsorption can change the formation wettability to oil-wet conditions. It was found that the damage resulting from corrosion inhibitors was more pronounced at lower temperatures and those mutual solvents tend to reduce the magnitude of the problem.

A mutual solvent being a compound that exhibits significant solubility in both oil and water and helps to dissolve both the adsorbed inhibitor and the acid-insoluble residue.

Many chemicals, including alcohols, ketones, and ethers, can be classified as mutual solvents. The specific compound normally referred to is glycol ether.

For sandstone acidizing a compound often applied is ethylene glycol monobutyl ether (EGMBE). In addition to its mutual solubility EGMBE also somewhat reduces the interfacial tension between oil and water and helps to remove adsorbed films from reservoir rock.

Gidley reported that the productivity of oil wells in sandstone formations treated with HF- HCl increased five- to sixfold over that found with regular HF-HCl treatments if as much as 10 wt% EGMBE is used in the diesel oil afterfiush of the treatment. A mutual solvent should not be added to either the preflush or to the HF-HCI mixture since it will reduce the effectiveness of the corrosion inhibitor.

Thus in some cases, apparently lower reservoir temperatures, a reasonable afterflush might consist of diesel oil containing EGMBE to help speed the removal.

Chapter 5 Designing Calculations for Selective Case

Designing of sandstone acidization.

Designing of acidization comprises of following

a) Preflush Volume
b) Acid treatment
c) Afterflush
d) Acid additives

Preflush Volume

The preflush is an important feature of a sandstone acid treatment. The main purposes of the preflush are as follows-

- To remove those formation materials which will react to a significant extent with HF, to displace those formation waters containing ions (Na+, Ca4" +, etc.) which will tend to precipitate with HF.
- To cool the formation in order to obtain deep penetration of acid.
- To displace the iron present as minerals siderite and ankerite, iron can precipitate from spent acid solutions to yield a damaging amorphous gel.

To accomplish these purposes, a large volume of preflush seems to be desirable. Larger volumes should ensure better contact of the preflush with the formation materials, better removal of undesirable reaction products from the near-wellbore region, and more efficient cooling of the formation near the well-bore. By diluting 15 wt% HCl acids to obtain 7.5 wt% solutions, one can increase the volumes of fluid used without substantially increasing the cost and perhaps ease the task of inhibiting the corrosion.

If corrosion is a substantial problem, preflushing with formic acid is acceptable. Because of incomplete reactions, higher molecular weight organic acids are not recommended

To ascertain the volume of preflush that should be used in a given situation, all HCl-soluble components must be removed from the near-wellbore region that is to be treated by the HF-HCI mixture. Thus, the volume of preflush is a function of the penetration depth of the main HF-HCI acid treatment and the volume fraction of acid-soluble minerals residing in that zone.

Preflush volume is function of porosity, composition of formation and depth of damage (generally 1 feet).

Preflush volume= $\pi(R_s- R_w)^2*H*(1-\phi)*$(percentage of carbonate mineral)...........(5.1)

Rs= Depth of damage radially

Rw= Radius of well

H = Height of formation

ϕ= Average porosity of formation

Acid Treatment

Designing of acid treatment includes rate of injection, composition of mixture, volume of mixture.There is little advantage to be gained by acidizing an undamaged formation .Consequently, it is essential to restrict the injection rate and injection volume such that acid used to dissolve rock in damage zone.Thus it seems self-evident that given a volume of acid, the optimal application will be to dissolve rock in the damaged zone. Acid reacted in the regions beyond the damaged zone will be of little utility.. Thus, the injection rate should be adjusted to ensure that the overwhelming bulk of the acid is spent within the damaged region.

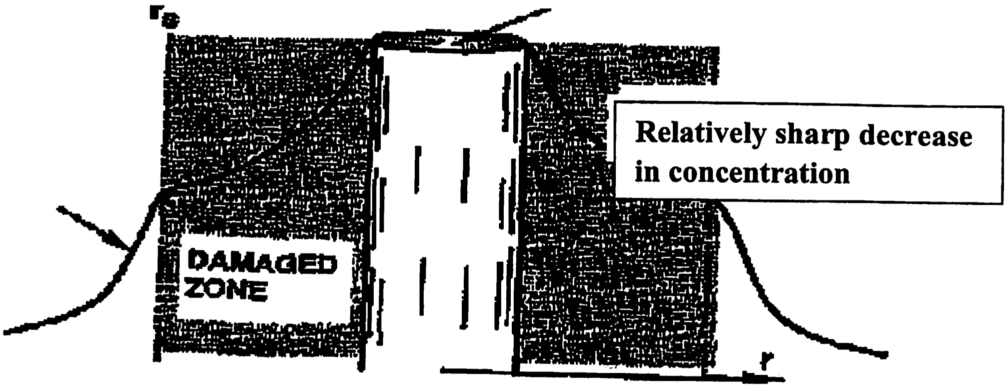
In addition to restricting the reaction of acid to the damaged zone, the design strategy imposed here also requires that the amount of acid expended in removing the slow-reacting minerals be minimized because if the damage is caused by debris dislodged from the rock surfaces it is almost certainly composed of fast-reacting minerals. Furthermore, fines from drilling, completion, or cementing fluids that have entered the pore spaces and clogged the pore throats are also likely to be highly reactive with HF if they react at all. Thus, the strategy of most efficiently removing the fast-reacting minerals from the damaged zone appears to be a logical one even though experimental evidence proving this to be the case does not now exist.

Optimum acid injection rate will be different for each acid treatment. An optimum value of a dependent variable exists as a compromise between competing forces. In this case a slow injection rate will yield a sharp reaction front, as shown by Fig. 16.12(a) and little of the fast-reacting minerals will be dissolved beyond the damaged zone. Because the injection rate is slow, however, the acid experiences a long contact time with the slow-reacting minerals behind the front and much of it is spent in unfruitful reactions with these minerals.

If the injection rate is increased, then the amount of acid reacting with the slow-reacting minerals is correspondingly decreased as shown by Fig. 16.12(b), but now the reaction front may become diffuse and unwanted reaction with the fast-reacting minerals beyond the damage zone may take place.

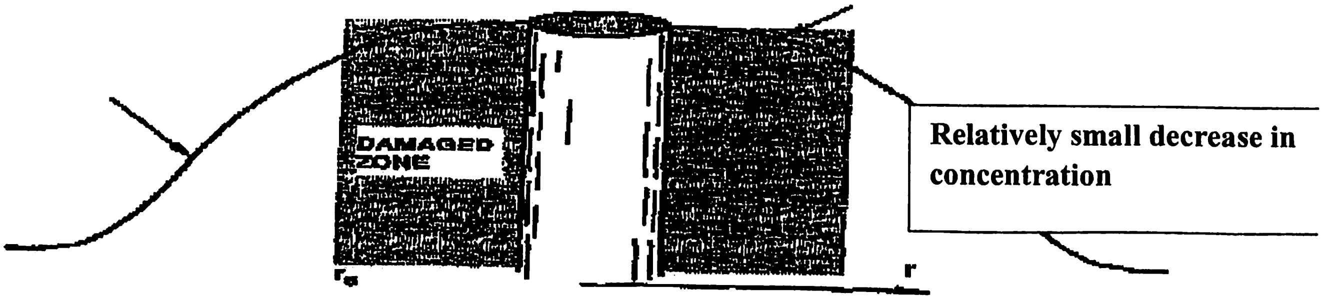
The amount of acid required to remove most of the minerals from the damaged zone will be a minimum when the injection rate is fixed at the optimum value. It should be noted that in some cases the optimum injection rate will exceed the maximum one permitted and therefore these treatments are simply designed based on the maximum allowable rate. In this case it would be helpful to measure the bottomhole wellbore pressure during the treatment so that as damage is removed and the wellbore pressure declines, the rate can be adjusted upward to more nearly approach the optimum value.

The depth of the damaged zone is rarely known, and most acid treatments are designed by first selecting a given volume of acid to be used. Associated with this volume is an optimum injection rate. According to the strategy defined here, it can be argued that small acid volumes correspond to small injection rates.



Relatively sharp decrease in concentration

CASE A: SLOW INJECTION RATE



Relatively small decrease in concentration

CASE B FAST INJECTION RATE

Fig 5.1 Schematic diagram showing effect of acid injection rate has upon acid concentration and reaction front. The profile of acid composition will depend on the injection rate, (A) Slow Injection Rate: Large decrease in concentration in the zone behind the front and sharp front, (B) Fast Injection Rate: Small decrease in concentration in the zone behind the front and diffuse front.

Rate of Acid injection – Injection rate should be such that pressure against sandface less than fracture pressure.

Fracture pressure= (Fracture Gradient)*(Depth of formation)

Fracture Gradient= (FG)*(Depth of formation)

$$\frac{p_{\mathrm{BISIP}}}{D} = FG = \left(\frac{\nu}{1-\nu}\right)\rho_o g + \frac{p}{D}\left(1 - \frac{\nu}{1-\nu}\right)$$

……………(5.2)

υ= Poisson's ratio (0.25- 0.4)

Rho=density of rock (2290 kg/ m^3)

P = Reservoir Pressure

D=Vertical depth of formation

P_{BISIP}= Bottom hole shut in pressure

Maximum injection rate can be obtained by using following equation

$$p_{wf} - p_R = \frac{i\mu}{2\pi kh}\left[\ln\left(\frac{r_e}{r'_w}\right) - \frac{3}{4}\right]$$

…………………………………………(5.3)

$$r'_w = r_w \exp(-S)$$

……………………………………………………………………(5.4)

P_{wf}= Injection pressure(FG*D)

P_R= Reservoir pressure

μ=Viscosity of acid mixture

r_e= Drainage radius

r_w=Radius of well

r'_w= Effective wellbore radius

K= average permeability

H=Thickness of formation

S= skin

Injetion rate of acid mixture must be less than maximum injecton rate. Above maximum injection rate formation will be fractured. In addition to maximum injection rate constraint, rate of injection should be optimal. Using Damkohler's number , rate of injection for fast reacting minerals and slow reacting minerals can be determined. Optimal injection rate is one which satisfies dissolution of both fast reacting minerals and slow reacting minerals An accurate estimate of this quantity is quite difficult to obtain without experimental data. Unfortunately, these data are rarely available. Damkohler numbers for Berea and for a Phacoides sandstone are available. As a crude estimate a scaling procedure is recommended as follows

$$D_a^{(R,F)} \simeq \frac{(D_a^{(F)})_B V_F^0 (1 - \phi_0) E_f(T) u_B \pi r_w^2 h}{(V_F^0)_B (1 - \phi_0)_B E_f(T_B) L_B i}$$

...........(5.5)

The subscript B denotes values obtained using Berea or any other standard linear core test. Petrographic and X-ray analyses of representative samples of the Berea cores that were acidized to obtain the results 4]. Clay (illite and chlorite) is present as rock fragments and thus is classified together with quartz as a slow-reacting mineral [14]. Once the carbonates are removed, then petrographic analysis shows $(V^o_F)_B = 0.052$ and $(1 - \phi)_B = 0.79$. It also consist of rate function dependent on temperature

Reaction front inside formation should be sharp enough to satisfy the dissolution of slow reacting and fast reacting minerals then the required Damkohler number is

$$D_A^{(R,F)} = -\frac{\ln\left[\left(\frac{1}{\psi_1}\right) - 1\right]}{\delta(\epsilon_f^{(R)} + 1)}$$

..........................(5.6)

Where $\psi = C_{HF}/C_{HFo}$

$\delta = \Delta r/r_f$

Δr= Width of zone

r_f= Distance travelled by front

$$D_a^{(R,S)} = D_a^{(S)} \left(\frac{u}{L}\right) \frac{E_f^{(S)}(T)}{E_f^{(S)}(298)} \left(\frac{\pi r_w^2}{i/h}\right)$$

..............................(5.7)

Using Damkohler's number for slow reacting mineral, the acid concentration at the reaction front can be determined by following equation-

$$\psi = \exp(-D_a^{(R,S)} \epsilon^{(R)}) \qquad (\text{for } \epsilon^{(R)} \leq \epsilon_f^{(R)})$$

.....................(5.8)

$\varepsilon_f^r = (r_s/r_w)^2 - 1$...(5.9)

Second step toward designing of job is calculation of acid volume. It requires determination of Acid capacity number

$$A_c^{(F)} = \frac{\phi_0 \beta_F c_{HF}^0 M_F}{(1 - \phi_0) V_0^F \rho_F}$$

....(5.10)

On the basis of formation lithology, average value can be determined

$$\frac{V_0^F \rho_F}{\beta_F M_F} = \sum_i \frac{V_{0,i}^F \rho_{F,i}}{\beta_{F,i} M_{F,i}}$$

....(5.11)

F= Indication of fast reacting minerals

Rho$_F$= Density of fast reacting minerals

M$_F$= Molecular mass of fast reacting minerals

V$_o$= Volume of fast reacting minerals

β_F=Moles mineral/ Moles of HF

Using Acid capacity number and Damkohler's number pore volume (acid mixture) being injected into the formation can be determined.

$$\theta^{(R)} = \frac{\exp(D_a^{(R,S)}\epsilon_f^{(R)}) - 1}{A_C^F D_a^{(R,S)}} + \epsilon_f^{(R)} \qquad \text{...(5.12)}$$

The equation also relates the pore volume for the radial system to the penetration depth. It determines volume utilized by unit pore volume. Consequently, for specific damage length, volume of acid injection can be determined.

$$\theta^{(R)} = \frac{it}{\pi r_w^2 h \phi_0} \qquad \text{...(5.13)}$$

Where, i= Rate of acid injection

T= Time of acid injection

End result of acidization job is increment in productivity ratio. Productivity ratio depends upon permeability which finally depends upon porosity.

$$S = \left(\frac{k}{k_s} - 1\right) \ln \frac{r_s}{r_w} \qquad \text{...(5.14)}$$

$$\frac{J_s}{J_d} = \frac{\ln\left(\frac{r_e}{r_w'^{(D)}}\right) - \frac{3}{4}}{\ln\left(\frac{r_e}{r_w'^{(A)}}\right) - \frac{3}{4}} \qquad \text{...(5.15)}$$

Where $r_w'^{(D)}$= Effective well bore radius of damaged zone

$r_w'^{(A)}$= Effective well bore radius of acidized zone

Generally, composition of acid mixture for acidization of sand stone 12wt% HCL and 3wt% HF. It is also known as Mud Acid. Hydrochloric acid is used to keep the pH high, as low pH result in precipitation of insoluble reaction product. Composition of acid mixture should not cause damage to formation due to precipitation of insoluble product of reaction. Consequently, acid mixture is function of formation mineralogy, dissolving power of acid and desired increment in productivity ratio. Additives like corrosion inhibitors, surfactants etc are added to make process efficient.

Design of carbonate acidization.

Schetcher and Guidly, considered a collection of essentially parallel pores and calculated evaluated pore sizes based on the mechanism of 'pore-collision.' As the pore expands in area incorporating other pores thus depleting the total number and results in an increased permeability of the rock, but the tendency of the acid to flow through larger pores, the difficulty to characterize larger pores and a non real pore model causes difficulty in application of this model.

Hofner and Fogler used network models of connected pores; this approach indicated qualitative features of acid attack on carbonates but did not helped in exact modeling of the acidization process.

Fractal description of wormholes

Wormholes grow in an irregular geometry which can be thought of as a particle undergoing Brownian motion, our task of modeling wormhole geometry is same as that of characterizing this Brownian motion .One property that these irregular curves exhibit is that of self similarity and this property of self similarity can be used to find out the curve length

$$\mathbf{L(curve) = d^{n}{}_{f}} \ldots\ldots\ldots\ldots (5.16)$$

Here we restrict d to a certain range of lengths, over the range to which this equation applies the system is self similar and is termed as a fractal. The parameter nf defines the fractal dimensionality of the system.

Using two dimensional model analysis it has been found out that for wormhles $nf=1.6 \pm 0.1$.This result establishes a general charecterstics of wormholes applicable in a range of acid injection rates, reaction rates and
initial pore size distribution.

If the flow of acid through the pore spaces is slow than only the rock surfaces exposed directly to the acid will be dissolved and only the spent acid will travel to penetrate the rock. This can be thought of a slow acid reaction definate front which slowly receds as acid dissolves the rock.

If X is the acid dissolving power then iX volume of rock will be dissolved,with a simple volume balance equation

$$(1 - \phi)2\pi rh \frac{dr}{dt} = iX \qquad \text{...(5.17)}$$

If v_c is the velocity of the front, then

$$v_c = \frac{iX}{2(1 - \phi)\pi rh} \qquad \text{................(5.18)}$$

Here we have considered slow flow rates, in case of high flow rates the acid has less time to react and the invasion will be more or less homogeneous and thus wormholes do not develop.

Radial flow model

Considering an effective radius r(A) around the wellbore to which wormholes have penetrated afeer injecting a fixed volume of acid. Neglecting any pressure drop for incompressible flow into the formation from the wellbore,Here $r_A(t)$ is the depth of wormhole penetration into the formationBased on fractal dimensions and experiments Daccord claimed that at various injection rates-

$$v_D = b r_A^{(2-n_f)} N_{Pe}^{-1/3} \qquad \text{...(5.19)}$$

$$N_{Pe} = \frac{i}{D_A h} \qquad \text{...(5.20)}$$

The penetration distance achieved by given volume of acid is given by-

$$r_A^{n_f} - r_w^{n_f} = n_f b \frac{V_A X}{2(1 - \phi)\pi h} N_{Pe}^{-1/3} \qquad \text{...........................(5.21)}$$

This is our final design equation. The fractal dimension nf is an importanat quantity in determining the wormhole penetration distance and high injection rates are undesirable since this increases the Peclet number and thus reduces the penetration distance, however the injection rates that are too slow does not yield wormholes and thus this equation applies only when $N_{pe}>1$, bur according to Daccord this limit is of no practical importance abd thus this equation can be used in the design of carbonate matrix acidization.

Design of matrix acidization for carbonates

The design of matrix acidization for carbonates consist of specifying acid volume and type, the injection rate and pressure can be used without fracturing the formation.

The maximum injection rate is determined the fracture pressure and using the equation

$$p_{wf} - p_R = \frac{i\mu_r}{2\pi kh}\left[\ln\frac{r_e}{r'_w} - \frac{3}{4}\right] \qquad \ldots\ldots\ldots\ldots(5.22)$$

Here,

$$r'_w = r_w \exp(-S) \qquad \ldots\ldots\ldots\ldots(5.23)$$

The maximum allowable bottomhole well pressure is determined using equation

$$p_{wf} = (FG)(D) \qquad \ldots\ldots\ldots\ldots(5.24)$$

Using these equations the maximum injection rate is calculated, the maximum rate may further be reduced by the maximum allowable surface injection pressure. This design method yields optimum injection rates so small that the treatment time would be months, so we start by first limiting the time. Based on different injection rates ,pecklet number and radial penetration distance of the acid ,stimulation ratios are calculated. The correct acid injection volume and stimulation ratio selected depends on the economic analysis of the job.

Case study

Radius of the wellbore (r_w) = 0.15m.

Radius of the damaged zone (r_s) = 0.3048m.

Drainage radius of the well = 300m

Height of the pay zone = 5m.

Average permeability (K_{avg}) = 90mD.

Skin (S) = +6

Porosity (Ø) = 0.20

Composition of the formation

Mineral name	Volume (%)
Calcite	6
Siderite	4
Quartz	75
Orthoclase	6
Kaolinite	5
Montmorillonite	4

Here we have to design-

a) Preflush.
b) Acid-treatment.
c) Afterflush.
d) Additives required.

Calculation Of Preflush Volume

Preflush is designed to remove carbonates.

Volume of carbonates per meter of the of the formation = $\pi\ (r^2 - r_w^2)\ (1-\phi)\ f.$

$= 0.01695\ m^3/m$ of the formation

Since, the fraction of carbonates present here = 0.10

Here, 7.5 wt% of HCL is used as the preflush treatment, dissolving power of 7.5 wt% HCL = 0.041

Volume of preflush = 0.41 m^3/m of the formation.

Thus, total volume of preflush = 2.06 m^3 of the acid.A preflush of 7.5 wt% HCL, containing 2.06 m^3 of acid is used.

Acid Treatment

Here the amount of orthoclase minerals and orthogenic monmorillonite is substantial, so we have to use a acid containing a reduced concentration of HF to reduce the density of Si $(OH)_4$ precipitate that will inevitability form. A concentration of 1.5 wt % HF will therefore be used; however the HCL concentration will be maintained at 12 wt%. The treatment temperature would be maintained at 60 ^{0}C. the damage that can be directly attributed to Si $(OH)_4$ precipitation is not known and it seems prudent to take precautions to minimize its impact.

The radial Damkohler number for slow reacting minerals can be estimated using the equation-

$$D_a^{(R,S)} = D_a^{(S)}\left(\frac{u}{L}\right)\frac{E_f^{(S)}(T)}{E_f^{(S)}(298)}\left(\frac{\pi r_w^2}{i/h}\right)$$

Using recommended values,

$D_a^{(S)} = 0.62$

$u/L = 0.00124\ \sec^{-1}$

$E_f^S(T)/\ E_f^S(298) = \exp\ [-1150\ (1/T - 1/298)]$

Therefore, $\mathbf{D_a^{(S)} = h/I\ (9.19 * 10^{-5})}$

The optimal injection rate also depends on the radial Damkohler number characteristic for the fast reacting minerals. An accurate estimate of this quantity cannot be obtained without experimental data, as a crude estimate using Berea sandstone as a standard.

$$D_a^{(R,F)} \approx \frac{(D_a^{(F)})_B V_F^0(1 - \phi_0)E_f(T)u_B \pi r_w^2 h}{(V_F^0)_B(1 - \phi_0)_B E_f(T_B) L_B i}$$

Here the subscript B denotes the standard Berea sandstone values.

Once the carbonates are removed by the preflush,

$V_F^0 = 0.098$

$\phi^0 = 0.285$

$(V_F^0)_B = 0.052$ and $(1 - \phi_0)_B = 0.79$

Here the most prevailing fast reacting mineral is orthoclase, so

$E_f^S(T)/ E_f^S(298) = \exp[-4680 (1/T - 1/298)]$

Thus, $\mathbf{D_a^{(R,F)} = (h/i)\ 6.05*10^{-4}}$.

The radius of the damaged zone is 0.30m so the treatment strategy requires the reaction front to move to a position.

$$\epsilon_f^{(R)} = \left(\frac{r_s}{r_w}\right)^2 - 1$$

= 3.

To maintain a sharp reaction front,

$$D_a^{(R,F)} = \frac{-\ln(1/\psi_1 - 1)}{\delta(\epsilon_f^{(R)} + 1)}$$

Ψ is the acid concentration ratio on the upstream side.

And, δ is the reaction zone width.

These values of Ψ and δ have to be adjusted to maintain a sharp reaction front and to get an optimal injection rate, such that the formation does not get fractured.

	Case 1	Case 2	Case 3
Ψ	0.75	0.80	0.75
δ	0.30	0.30	0.26
$D_a^{(R,F}$	0.916	1.155	1.056

$(i/h)_{\text{case 1}} = 6060*10^{-4}$

$(i/h)_{\text{case 2}} = 5.23*10^{-4}$

$(i/h)_{\text{case 3}} = 5072*10^{-4}$

The optimal injection rate should be such that the formation does not get fractured, based on the equation,

$$p_{wf} - p_R = \frac{i\mu}{2\pi kh}\left[\ln\left(\frac{r_e}{r'_w}\right) - \frac{3}{4}\right]$$

Where P_{wf} = FG*Depth

Here r_w' is the effective radius in the presence of skin.

$$r_w' = r_w \exp(-S)$$

Solving the above equation gives, (i/h) = $6.20*10^{-4}$.

The (i/h) value selected from the radial Damkohler number characteristics should be maximum depending on the amount of acid consumed by slow reacting minerals.

Thus, (i/h) = $5.72*10^{-3}$.

Therefore, **i = $2.86*10^{-3}$, this is the desired injection rate.**

Now, the slow reacting Damkohler number is,

$D_a^{(R,S)} = 9.19*10^{-5} * (h/i) = 0.148$.

The acid concentration as it arrives at the reaction front is given by

$$\psi = \exp(-D_a^{(R)} \epsilon_f^{(R)})$$

$$=0.74.$$

Thus, 26% of the acid is consumed at the slow reacting minerals at the time the reaction front arrives at the damaged zone radius, this is a wise value in order to maintain a sharp reaction front.

Taking the acceptable value of the injection rate to be $2.86*10^{-3}$ to complete the design, it is now necessary to determine the acid volume.

The acid capacity for the fast reacting mineral,

$A_C^{(F)} = \phi_0 * C_{HF}^0/(1 - \phi_0)$*(Kg moles of HF/$m^3$ of the formation).

For calculating the acid capacity number,

Mineral	Density(Kg/m^3)	Volume (m^3 /m^3) of the formation.	Mass (Kg/m^3) Of the formation.	Moles (Kg/m^3) Of the formation.	B_F (moles mineral/moles HF)	Moles of HF per m^3 of formation.
Quartz	2650	0.111	2941.5	48.8	0	-
Montmorillonite	2400	0.059	141.6	0.136	0.018	7.55
Kaolinite.	2650	0.074	196.1	0.380	0	-
Orthoclase.	2600	0.088	228.8	0.830	0.050	16.6

Calculations made in the above table reveal that 24.15 moles of HF per m^3 of the formation is required, since the HF concentration $C_{HF}{}^0 = 0.81$.

Thus, $A_C{}^{(F)} = 1.437 * 10^{-2}$.

The pore volume for the radial system $\theta^{(R)}$ to the penetration depth is given by-

$$\theta^{(R)} = \frac{\exp(D_a^{(R,S)} \epsilon_f^{(R)}) - 1}{A_c^{(F)} D_a^{(R,S)}} + \epsilon_f^{(R)}$$

$\boldsymbol{\theta^{(R)} = 224.36}$

From the definition of $\theta^{(R)}$

$$\theta^{(R)} = \frac{it}{\pi r_w^2 h \phi_0}$$

Thus, it/h = Volume of acid treatment per m of the formation.

Volume of the acid treatment = 23.77 m^3.

And, the treatment time (t) = 30.64 minutes.

The new well productivity that may be expected as a result of this acid treatment can now be estimated, the permeability in the damaged zone can be estimated using the equation,

$$S = \left(\frac{k}{k_s} - 1\right) \ln \frac{r_s}{r_w}$$

Thus, $K/K_S = 9.656$.

The stimulation result in the final porosity is given by $\phi_{final} = 0.20 + [0.80\ (0.08+0.08)]$.

Now,

$$k/k_0 = \exp\left[M\left(\frac{\phi - \phi_0}{\Delta\phi_{max}}\right)\right]$$

Taking, $M/\Delta\phi_{max.} = 45.7$

$K/K_0 = 347.095$

Thus the new skin factor following the treatment,

$S_2 = (9.656/347.095 - 1) \ln 2 = -0.637$.

To determine the stimulation ratio we first have to calculate the effective wellbore radius following the acidization treatment, using the equation-

$r'_w(A) = r_w \exp(+S_2) = 0.294$

$r'_w(D) = r_w \exp(S) = 3.781*10^{-4.}$

Finally using the equation,

$J_S/J_d = [\mathrm{Ln}\ \{ r_e/ r'_w(D)\} - 0.75]/[\ \mathrm{Ln}\ \{ r_e/ r'_w(A)\} - 0.75] = 2.0799$

Thus the treatment is expected to double the current production rate.

Afterflush

The precitation of Si $(OH)_4$ may limit the success of sandstone acidization treatment. To minimize the impact of precitation an afterflush is employed and the well be retained to production immediately. The afterflush to be used is diesel oil to ensure that the precipitation from the spent acid occurs away from the critical region near the wellbore. This afterflush also serves to dilute the acid therby reducing the precipitation tendency.

Additives

We can use either mechanical or chemical diverting techniques, but since here we have only a single zone to be treated so the use of mechanical diverting techniques like that of inflatable packers would not be economically viable. Thus the use of chemical diverting techniques seems to be the preferred choice. Finely ground organic resins with a high molecular weight hydrocarbon resin that is aliphatic in nature, these resins exhibits considerable oil solubility and will be easily removed during production. The organic resin used should consist of a mixture of large particles mixed with smaller particles; this mixture will permit the formation of a low permeability filter cake on the sand face.

Here neither do we have high bottom hole temperatures, nor high contact time between the acid and metal is expected so, the compound used as inhibitor requires a favorable polar group or a group by which the molecule can attach itself to the metal compound, thus a amine compound in the concentration of 1 volume% of the acid treatment can be used.

It will be advantageous to add a mutual solvent to the afterflush for the purpose of removing unwanted corrosion inhibitors, which may have entered the formation and absorbed on the mineral or blocked the pore spaces. Ethylene glycol monobutyl ether (EGMBE) is used as an additive in the afterflush in a concentration of 10 volume% in the afterflush. It should not be added to the acid treatment nor to the preflush since its presence reduces the effectiveness of corrosion inhibitor that the amine compound.

Results & Recommendation

According to case study for acidization of sandstone, results are as follows-

Volume of Preflush per meter thickness of formation= 0.01695 m^3

Rate of Injection for acid treatment = $2.86*10^{-3}$ m3/ sec

Volume of acid mixture required for acid treatment = 23.77 m^3

Treatment time = 30.64 minutes

Final Productivity Ratio (J_S/J_d) = 2.0799

Concentration of acid mixture for acid treatment is 1.5 wt% HF and 12wt%HCl.

As per the case study, given well is oil well thus diesel oil can be used as afterflush. It is desired to push the spent acid 3-4 feet away from the well bore.

Recommendations

Recommendation for the matrix acidization are as follows-

- In case of acidization of multilayers reservoir, mechanical diverters like straddle packers can be installed.
- If optimum injection rate is higher than maximum injection rate, acidization can be done at lower rate than maximum rate. As skin remove with time, optimum rate can be achieved.
- Proper anticipation against damage of formation due to deposition of scales (corrosion of tubing during execution) is must. It is possible by using Coil Tubing Unit.
- Transportation of acids (liquid) should be done in tanker which is coated with inert material internally to avoid corrosion.
- Fluoroboric acid is also good alternative for acidization of sandstone as it provide deeper penetration.In this case mixture of Fluoroboric acid (HBF_4) and Hydrochloric acid (HCl) can be injected.
- Strategic implementation and detail laboratory study is required, regarding selection of acids and additives. Additives and acids used must be compatible with formation fluid and formation rock to make job successful.

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