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Simulation of Acidizing one of the Iranian South West Oil Wells

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Abstract

Most of Iranian petroleum reservoirs' wells have problem with their high skin, so petroleum engineers have seriously trying to find an efficient solution to help well to produce at optimum flow rate, but doing a treatment without prediction and evaluation may harm the reservoir instead of helping. Pumping of acid into the wellbore to remove near-well formation damage and other damaging substances, Matrix Acidizing, is one those solution that may help the well production. Success in matrix acidizing depends on true evaluation and investigation of actions between rock minerals and acid fluids. This procedure commonly enhances production by increasing the effective well radius. When performed at pressures above the pressure required to fracture the formation, the procedure is often referred to as acid fracturing.

This project is going to (1) explain about the well skin or damage and how it may happen in well, (2) how do acidizing treatment in carbonate reservoir, (3)introduce the modeling equations that are using in carbonate acidizing, and at last (4) examine them on a real case with special acidizing software and compare with real welltest analysis data.

The real case in this project has two welltest before and after an acidizing treatment. These testes give two different results in correct way that meaning the treatment was successful and skin has been reduced. It has been expected the software will predict skin reduction precisely.

Acknowledgments

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Introduction

Many excellent and useful papers have been written on the subject of matrix acidizing. Included in this article is an extensive bibliography that should be useful to the engineer in the design and execution of a matrix acidizing treatment in limestone or sandstone formations. The first matrix acidizing jobs were very successful in stimulating oil production in carbonates. However, most of the recent attention to matrix acidizing concerns sandstones and the use of various hydrofluoric acid systems. Matrix acidizing in carbonate formations still is beneficial in high-permeability, damaged formations (50 md or more). Damage can occur during drilling, completion, or production of a well. In carbonates with permeabilities less than 10 md, acid fracturing generally is used because much greater stimulation is obtained with long, acid-etched fractures in low-permeability reservoirs. Although the acid systems used in sandstones and carbonates differ, the same practices apply to both.[1]

Laboratory experiments on a gypsum model system and computer simulations show that for a given geometry, wormholes can be quantified by a unique parameter, their equivalent hydraulic length. Three types of etching can be obtained: compact, wormhole type, or homogeneous. The optimum conditions for achieving the best skin decrease correspond to the creation of wormholes and can then be defined in terms of fluid reactivity and injection rate.[2]

A joint project between ARGO and Schlumberger Dowell was initiated over two years ago with the objective of creating a matrix acidizing software programmer that would be commercially released and available to the industry. At this point in time there were no commercially available matrix acidizing software packages available in the market. By combining resources and expertise ,ARCO and Schlumberger Dowell , have launched the first commercially available matrix acidizing software package StimCADE that is reliable for forecast and evaluation of acidizing. [11]

Chapter 1: Damage and Skin

1.1 Well Performance (Need for Acidizing)

Successful acidizing depends on the presence of damage and its location and intensity. The closer the damage is to the perforations, the more easily acid can get to it. Compacted or crushed zone damage from perforating overbalanced can be removed easily by acid, since only about 1/2 in. [1.3 cm] of damage must be removed directly around the perforation. Precipitates from previous acid treatments more than 1 ft [0.3 m] from the wellbore in sandstone or 5 ft [1.52 m] in carbonate will be either impossible to reach with matrix acidizing or too expensive to treat. [1,3]

Deep solid plugging will be corrected more effectively by creating a conductive fracture through the damage either by sand fracturing or acid fracturing. Nonplugging damage (e.g., oil wetting) may be several feet deep around the wellbore, but reverse wetting surfactants can penetrate and reverse the formation to a water-wet condition at reasonable cost. Oil wetting damage usually is less severe than solid plugging damage, so corrective chemicals can reach the affected area easily.

High-permeability formations (those with 100 and or more) seem to be dominated by either formation damage or tubing size flow restrictions. This is particularly true of gravel-packed offshore wells. When well flow is markedly less than similar wells in the same reservoir, most of the drawdown probably is occurring at the wellbore through a small zone of reduced permeability. Most recent gravel-pack-damage research has focused on gravel-packed tunnels and quality of the gravel in the tunne1. Current techniques have improved so much in recent years that gravel-packed tunnels usually offer little flow resistance when perforating density is adequate. Nevertheless, reduced flow through gravel-packed wells still occurs.

Current research focuses on (1) incompletely packed tunnels and (2) formation-sand damage near the entrance to the tunnels. Damage to formation sand before gravel placement will cause premature pressure outs resulting from viscous fluids entering damaged or reduced permeability near the perforations. Because of high pressures, pumping may be halted before the gravel has concentrated adequately in the perforation tunnels. If the pumping stops too soon, the tunnels will be filled only partially with quality gravel. When the well is produced, formation sand will enter

the tunnels, bridging on the gravel inside the tunnel and packing the partially void tunnel with formation sand, which is much lower in permeability than the gravel. As the formation sand fills the tunnels, the pressure drop through the completion increases and the flow rate declines.

This type of damage can be removed partially by acidizing, but the completion will never reach its expected potential. A damaged completion may produce only 50 to 100 B/D [7.9 to 15.8 m^3/d] oil before acidizing and 100 to 300 B/D [15.8 to 47.4 m3/d] oil after acidizing; whereas the potential of the undamaged formation may be 1,000 to 2,000 B/D [158 to 316 m3/c1] oil or more. The true potential of the well can be reached only by replacement of the gravel pack. Less severe damage will occur if the gravel is placed correctly in the perforation tunnel. If little or no gravel is placed outside the tunnel, formation sand will about the tunnel entrance at the cement formation interface (Fig. 1).

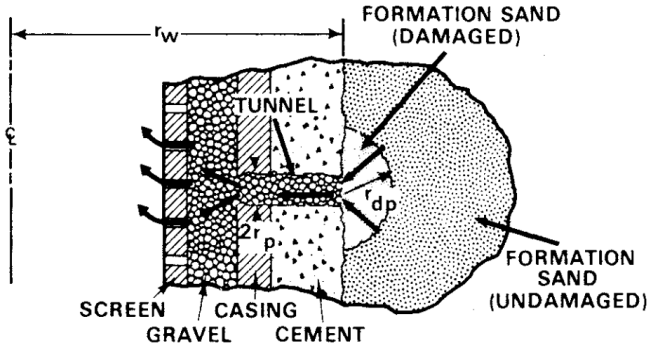


Fig. 1 – Gravel-packed tunnel with collapsed perforation [1]

If this formation sand is clean and permeable, the pressure drop -caused by spherical flow through the formation sand to the tunnel will be small; however, if any damage exists from polymer residue, pipe dope, or formation fines, the pressure drop can be substantial and flow greatly reduced. Damage can be removed with acid to achieve high gravel pack flow potential. [1,4]

Successful acidizing in these cases depends on the severity of the damage and the choice of the solvent used during the treatment. Success also depends on (1) favorable response of the formation to acid and (2) successful acid treatment execution. If damage is moderate (less than 90% loss in permeability), acid usually can dissolve the damage. If damage is severe (more than 99% loss in permeability), acid may not enter the perforation fast enough to dissolve the damage. Much

research and laboratory testing of acid stimulation have been performed on permeable Berea sandstone cores; however, little research has been performed on severely damaged cores. More testing also is needed in actual wellbores, where clean and plugged perforations or perforation tunnels may exist side by side. Even in a damaged well, there may be significant reservoir pressure drops during flow. Relative pressure drops in the reservoir and in the completion should be evaluated by accurate pressure transient testing. [1,5]

These well tests provide formation permeability data and a skin factor that characterizes the degree of damage. Skin factors as large as +30 may occur and well productivities can be only 20% of maximum, undamaged potential. Before performing an acid treatment it is important to analyze

the source of the skin. Is the damage being caused by solids plugging, wettability alteration, or some other condition that acid may not be able to remove? These conditions could include insufficient perforation density or two-phase flow (relative permeability or capillary pressure) restrictions. There are three main components to successful acidizing: (1) well preparation, (2) selection of solvent to remove damage, and (3) formation response to acid. [1]

1.2 Damage Removal by Chemical Solvents

Selection of a chemical for any particular application will depend on which contaminants are plugging formation permeability. HCl will not dissolve pipe dope, paraffin, or asphaltenes. Treatment of these solids or plugging agents requires an effective organic solvent (usually an aromatic solvent like toluene, xylene, or orthonitrotoluene). Acetic acid effectively dissolves calcium carbonate scale; however, it will not dissolve ferric oxide (iron oxide) scale. HCl dissolves calcium carbonate scale quite easily but has little effect on calcium sulfate scales. Calcium sulfate can be converted to calcium carbonate or calcium hydroxide by treatment with potassium hydroxide or sodium carbonate.

HCI then can be used to dissolve the converted scale. Calcium sulfate also can be dissolved in one step with the sodium salt of ethylene diamine tetraacetic acid (EDTA). HCI will not dissolve formation clay minerals or drilling mud. Hydrofluoric acid (HF) must be used to dissolve these aluminosilicates in rock pores around the wellbore. Because different plugging solids require different solvents for their removal, there is no universal solvent for wellbore damage. Treatment based on such a premise often will yield disappointing results. It is important to know the specific material that is damaging the formation around the wellbore. Never pump solvent or acid into a well until the cause of the damage and the best chemical to remove the damage have been defined. [1]

1.3 Formation Damage

To identify the damage or plugging solids that must be removed by a solvent, you must be familiar with the main types of damage that occur in oil, gas, and water wells. Oil well damage usually occurs during drilling, cementing, perforating, gravel packing, production, acidizing, well

workovers, chemical treatments, and injection operations. (The following paragraphs recommend HF only for sandstone formations; HCI is recommended for carbonates.) [1]

1.3.1 Drilling

Whole mud may invade extremely permeable formations with vugs or natural fractures such as those in many prolific carbonate reservoirs. These carbonates respond to large-volume, high-rate acid treatments. Even high-permeability sandstones (about 1,000 md) may be damaged by poorly conditioned mud. Glenn and Slusser (1957) showed that high-permeability formations could be invaded to significant depths by bentonite mud. However, if the mud contains properly sized bridging particles likebarite, whole mud does not invade a sandstone. Mud filtrates damage some sandstones because of swelling or migrating clays. High-calcium muds may cause near-weIlbore calcium carbonate precipitation if formation waters are high in bicarbonate ion content. Damage by whole mud or formation clays may be removed by appropriate HF treatments for sandstones and FICI treatments for carbonates. [1,6]

1.3.2 Cementing

Damage by cement filtrate (which usually contains calcium hydroxide or forms of calcium silicate) is reduced by good fluid-loss control in the cement slurry. Calcium hydroxide may be removed with either acetic acid or HCl. Calcium silicates must be removed with HF. [1]

1.3.3 Perforating

Damage may be severe when perforating overbalanced in the wellbore (hydrostatic pressure in the wellbore is higher than reservoir pressure). Permeability around the perforated hole may be reduced to from 2 to 20% of original permeability, depending on the nature of the perforating fluid. [1,3]

Overbalanced perforating will reduce permeability by compacting and plugging pores with crushed formation fines, perforating debris, and contaminants in the perforating fluid. Perforation damage usually is removed with HF in sandstone formations or with HC1 in carbonate formations.

1.3.4 Gravel Packing

Heavy damage in gravel packing can be caused when high-density gel/gravel slurry is pumped down into the perforations. Pumping this gel/gravel slurry down dirty pipe will squeeze pipe dope, mill scale, and other contaminants into the perforations. Squeezing poorly hydrated polymers into the perforations also can damage both the formation and the gravel. Damage by formation clays occurs when perforations are washed before gravel packing. Such damage can occur easily in formations with interbedded layers of sand and clay. Perforation washing will mix these layers and plug the permeable sand layers. If clay damage does occur, HF can be used to remove it.

Where severe pipe dope damage exists, acid may not penetrate the plugged perforation. The best practice is to avoid squeezing pipe dope into the perforations in the first place. Tubing may be cleaned by pumping acid down the tubing and then reversing to the surface. All dirty, spent acid should be produced back to a pit or tank before the gravel slurries are pumped into the perforations. Using solvent/surfactant soak treatments may loosen the pipe dope before acidizing the perforations, but if pipe dope damage is allowed to occur, it is difficult to correct completely. [1,4,7]

1.3.5 Production

Damage to a producing well can be caused by formation movement, scale formation (precipitated solids), and casing leaks. Whole formation production (collapsed perforations) can occur in weak or friable sands. This may be corrected by gravel packing or some other method of effective sand control. Fines migration also can occur. Fines can move through the reservoir and bridge at or near the perforations to cause in-situ filter cakes (plugging) inside the large pores in the sand. When casing leaks occur, either incompatible formation waters or drilling mud residues may contaminate the perforated interval. Casing leak damage usually is treated with HF for sandstones or HCl for carbonates. [7]

1.3.6 Acidizing Damage

If acid is bullheaded down tubing into a formation, pipe dope and/or iron scale (mill scale) may be squeezed into the formation with the acid. The first acid that enters the formation already may have

spent itself on iron oxide scales. Formations with either high concentrations of iron minerals or low permeability and abundant clay also can be damaged by acid injection.

Formations can be damaged easily by improper use of HF. Spent HF will precipitate silica, calcium fluoride, and other compounds, especially when not enough HCI preflush is used to remove calcium carbonate in the formation prior to pumping the HF. [1,3,7]

1.3.7 Well Workovers

Workover fluids often contain suspended solids that can plug formation pores. Some produced brines contain corrosion inhibitors or emulsion breakers from previous surface treatments that tend to oil wet the formation. Pumping cool fluids sometimes can cause paraffins or asphaltenes to precipitate in certain oil-hearing formations. Residual cement from casing repair jobs (or squeeze cementing operations) may damage perforations. Wireline work may loosen iron scale or paraffin from the tubing. With all these possible forms of damage, it is important to maintain detailed records of what is pumped into and produced out of a well during workover.

Workover fluid solids will settle into the rathole during the workover. Borehole samples may be collected with a wireline bailer and analyzed in the laboratory to show what substances may have damaged the formation. Once the most likely cause of the damage has been determined, choose the correct acidizing technique to remove the damage. For example, organic solvents may dissolve paraffin and asphaltenes. HCI dissolves sulfide or iron oxide scales. HF dissolves cement residue. Proper surfactants and/or solvents restore water wetness to the formation. [1]

1.3.8 Chemical Treatments

Scale inhibitors can oil wet carbonates and corrosion inhibitor treatments can oil wet sandstones. Damage cannot be prevented when these treatments are necessary to keep the well in operation; however, some inhibitors cause more damage than others. Variable degrees of damage have been observed in corrosion inhibitor treatments of gas wells. Atomized nitrogen treatments seem to be less damaging than oil squeezes when injecting corrosion inhibitors in gas wells. Sometimes severe damage may be corrected by using tested solvent/surfactant wash treatments. [1]

1.3.9 Injection Wells

Injection wells may be damaged by oil carryover, corrosion products, incompatible water scales, and bacteria. Damage from oil carryover and associated contaminants may be treated by solvent/acid dispersion. Corrosion products and calcium carbonate scale are removed easily with HCI. Calcium sulfate scale must be converted to an acid soluble form or dissolved in one step with a soak of EDTA. Bacteria must be destroyed by an oxidizing agent (bleach) and/or special bacteria-destructive agents before acidizing for complete removal.

Open communication and close working relations between engineers and operating personnel aid well problem diagnosis. Excellent completion and workover files are essential to analyzing wells that have been damaged. [1]

1.4 Formation Analysis

It is sometimes easy to dissolve plugging solids. The key to success, however, is to dissolve the plugging solids without damaging the formation. You must know how the formation minerals will respond to the acid used in the treatment and anticipate how the spent acid will react as it invades deeply into the formation. Solids dissolved near the wellbore may precipitate deeper into the One goal of formation analysis is to control or prevent precipitation of reaction products in the formation. Several contributions have been made in this area by D.K. Davies.

Acid treatments for shaly, low-permeability formations require more care than treatments for cleaner, high-permeability zones. More positive methods for zone coverage (e.g., opposed cup packers, ball sealers, diverting agents) are required to assure uniform acid placement in nonuniform, layered deposits. Formations with a large amount of fines or clay minerals must be analyzed to determine the best acid, acid concentration, and appropriate additives for successful stimulation. Estimates of permeability and wellbore condition help predict injection rates before and after acid stimulation at injection pressures less than formation parting pressure. Formation quality is defined by depositional, detrital, and diagenetic quality. [1]

1.5 Acids and Additives

The kinds of acids to use have been discussed in the section on formation damage; the concentrations of acid to use are listed in Table 1.26 Acid concentrations are determined more by formation mineralogy than by the plugging solid damaging the formation. Various concentrations of acids will dissolve damage, particularly small amounts of damage critically placed around the perforations; however, lower acid concentrations reduce precipitate problems in acid-sensitive formations. All additives should be tested in the laboratory.

Compatibility of both live and spent acid with the formation fluids should be tested. There are no universal additives for all formation acidizing problems. Field results and laboratory testing need to go hand in hand. A more thorough discussion is provided by other authors. Any potential incompatibilities between acid and formation solids or fluids must be identified before acidizing. 26,126-128 Fluid buffers may be used to isolate formation fluids. Acid concentrations and/or additives are tailored to formation mineralogy. Surfactants should leave the formation in a water-wet state for maximum oil or gas producing rates. [1,7]

Carbonate Acidizing
Perforating fluid
5% acetic
Damaged perforations
9% formic
10% acetic
15% HCl
Deep wellbore damage
15% HCl
28% HCl
Emulsified HCl
Sandstone Acidizing
HCl solubility (≥20%)
Use HCl only
High permeability (100 md or more)
High quartz (80%), low clay (<5%): 12% HCl and
High feldspar (>20%): 13.5% HCl and 1.5% HF*
High clay (>10%): 6.5% HCl and 1% HF**
High iron chlorite clay: 3% HCl and 0.5% HF**
Low permeability (10 md or less)
Low clay (<5%): 6% HCl and 1.5% HF†
High chlorite: 3% HCl and 0.5% HF‡

* Preflush with 15% HCl.
**Preflush with sequestered 5% HCl.
†Preflush with 7.5% HCl or 10% acetic.
‡Preflush with 5% acetic.

Table 1 – Acid use guidlenes [1]

Chapter 2 : Acidizing in Carbonate Reservoir

Much less is known about matrix acidizing of carbonate reservoirs than sandstone acidizing; models for sandstone acidizing have existed for more than 10 years. The main reason for this lack of knowledge is that in sandstone acidizing the kinetics of dissolution is limited by the surface reaction, which makes, in a first approximation, the global reaction rate insensitive to the flow rate and the displacement stable (the rock is homogeneously etched, in spite of possible large-scale instabilities), thus allowing a macroscopic formulation

In contrast, it is well known that the acidizing of carbonates with highly reactive acids leads to the creation of wormholes-Le., empty channels that bypass most of the matrix. This seems to be the result of the mass-transfer limitation of the kinetics. This characteristic causes the local reaction rate to be velocity-dependent and therefore the etched pattern to display instabilities. Little quantitative knowledge in this domain has been gained recently. Several more or less qualitative studies have aimed at understanding the key parameters limiting the extension of the wormholes ; it is currently believed (more intuitively or by analogy with fracture acidizing than from laboratory works) that decreasing the diffusion constant or increasing the acid flow rate will improve the penetration of the live acid.

1.6 Methodology of Treatment Fluid Selection for Carbonates

Other significant diagenetic minerals usually are soluble in HCI. Calcite and dolomite are dissolved easily in HC1 and cause no secondary precipitation problems. In fact, if a sandstone contains 20% or more of HCI soluble minerals, HC1 alone can remove damage. [1]

Problems with dolomite and calcite occur only when they are associated with other acid-soluble minerals such as the iron compounds: siderite (iron carbonate), ankerite (iron-rich dolomite), hematite or limonite (iron oxides), and pyrite (iron sulfide). HC1 dissolves the iron compounds, which then can reprecipitate as the acid completely spends on the calcite and dolomite. Iron compound precipitation may be prevented or controlled by iron-sequestering (complexing) agents in the acid. [1]

The decision tree for carbonate reservoirs is presented in Figure 2. Carbonate formations are mainly made of calcite (CaCO3) and dolomite (Ca,Mg(CO3)2) minerals, which are both readily

soluble in hydrochloric acid. Thus, in carbonate acidizing, unlike sandstone acidizing, the acid reacts with the rock but generally not with the damage (except for scales). The acid either bypasses the damaged zone by creating new channels in the rock ("wormholes") and/or creates a flow path (etched rock) for damage removal.

In addition to HCI, organic acids (such as acetic or formic acid) or acetic-hydrochloric acid mixtures are used. Under comparable conditions, organic acids react more slowly than hydro-chloric acid (Nierode and Williams, 1971; Hen-drickson, 1972). In acetic-hydrochloric mixtures the HCl reacts rapidly, whereas the organic acid reacts slowly.

The reactions of HCI with calcite and dolomite are as follows.

$2HCI + CaCO_3 = CaCl_2 + OH_2 + CO2$ (11)

$4HCI + CaMg(CO_3)_2 = CaCl_2 + MgCl_2\ 2OH_2 + 2CO_2$ (12)

Possible problems (like sludging) are solved with the use of specific additives in the acid or in the preflush.

The aim of carbonate matrix acidizing is to re-store the natural "skin value" of the formation. Under wormholing conditions and mass-transport limited kinetics, this is achieved when the penetration is maximum, i.e., with high-reactivity acids (Daccord et al., 1989). [3,8]

1.7 Mechanisms in Carbonate Matrix Acidizing

When acid is pumped into a carbonate (limestone or dolomite) at pressures below fracturing, the acid flows preferentially into the region of highest permeability — the largest pores, vugs or natural fractures. Acid reaction in the largest pores causes the formation of large, highly conductive flow channels called wormholes. Highly reactive acids tend to form a limited number of wormholes, while less reactive acids form more numerous, shorter and smaller diameter wormholes (Hendrickson, 1972).

The distribution of porosity is particularly important at the beginning of the reaction when the wormholes start to grow. Earlier work by Row-an (1959), Schechter and Gidley (1969) and Guin and Schechter (1971) showed that the number of wormholes is determined by the heterogeneity of the formation (pore-size distribution). [8]

1.8 Criteria In Carbonate Acidizing Fluid Selection

1.8.1 Temperature

Temperature influences the fluid selection in two ways. • It strongly influences corrosion inhibition of the acid. At high temperatures, greater than 300°F- (150°C), protection of tubular goods can hardly be achieved in the presence of 28% hydrochloric acid. Thus, the HCI concentration is reduced to 15% or less, and organic acids, less corrosive than HCI, are used in partial or total replacement of HCl.

• The acid-rock reaction rate increases with temperature.

1.8.2 Mineralogy

Whether the carbonate formation is a pure limestone or a partially (or totally) dolomitized carbonate must be considered initially. Specific treatment fluids have been developed for dolomitic reservoirs. At low temperatures, the reaction rate is much lower with pure dolomite. "Intensified Acid" is designed to dissolve dolomite that contains up to 5% silicates, e.g., quartz, feldspars or clays.

An impure dolomite, containing quartz grains scattered in the dolomitic matrix, is shown in Figure B-9. When the insoluble minerals, are clays or fines, dissolution of the rock matrix will ' result in the release of insoluble fines. A fines-suspending fluid like MSR is recommended. Dolomite is frequently associated with anhydrite (anhydrous calcium sulfate). Rocks containing anhydrite as a secondary pore filling and as a material sealing natural fissures, anhydrite will first be dissolved in HCI, but gypsum (hydrated calcium sulfate) will quickly reprecipitate because of its low solubility. Fluids with good chelating properties, such as MSR or NARS, are recommended to minimize this problem.

Dowell Schlumberger Acid System	Description	Treatment or Reservoir Conditions	Recommended Applications	Advantages
Dowell Schlumberger	Inhibited HCl 5% to 15%.	Production restricted due to damage or low formation permeability (80° to 400°F).	Matrix Acidizing and Acid Fracturing; Carbonate and Iron Scale Solvent.	Economical and versatile.
Dowell Schlumberger Super X	Inhibited concentrated HCl 20% to 28%.	Production restricted due to damage or low formation permeability (80° to 350°F).	Matrix Acidizing or Acid Fracturing; removal of formation damage or scale deposits.	Greater dissolving power than equal volume of Dowell Schlumberger X.
Dowell Schlumberger XX Intensified Acid	Inhibited HCl with HF intensifier.	Low or damaged permeability in dolomite or siliceous limestone reservoirs (80° to 400°F).	Matrix Acidizing or Acid Fracturing.	Accelerated reaction rate with dolomite and siliceous limestone.
Low-Surface-Tension Acid	Inhibited HCl and special surface-tension lowering agent.	Low formation permeability need to maintain low surface and interfacial tension (80° to 400°F).	All applications.	Lower surface tension; easier return of treating fluids.
Alcoholic Acid	Blend of inhibited HCl acid and alcohol (isopropyl alcohol or methanol).	Low-permeability carbonate reservoirs (80° to 250°F).	Matrix Acidizing or Acid Fracturing.	Low surface tension maintained in spent acid; reduced water saturation and improved relative permeability to gas and oil.
Gas Well Acid	Blend of inhibited HCl acid and alcohol.	Especially good for "dry" gas reservoirs; also damaged permeability in oil reservoirs (80° to 250°F).	Matrix Acidizing where low reservoir pressures retard cleanup.	Improved well cleanup due to low interfacial tension and increased volatility.
Breakdown Acid (BDA)	Low concentration inhibited HCl with special surfactants.	Removes formation damage and aids formation breakdown prior to further treatment (80° to 250°F).	Formation Breakdown Fluid; Matrix Acidizing and Acid Fracturing Spearhead.	Disperses mud filter cake and reduces formation breakdown pressures.
MSR100, MSR150 (Dowell Schlumberger Mud and Silt Remover)	Blend of 7.5% to 15% inhibited HCl acid and special clay dispersing, suspending and chelating agents.	Drilling muds lost to the formation; or reservoir has a high percentage of silts and clays (80° to 250°F).	Matrix Acidizing; Acid Fracturing; Formation Cleaning; Wellbore Cleanup and Gravel-Pack Cleanup Fluid.	Brings back large amounts of muds and clays; minimizes reprecipitation of dissolved iron.
Dowell Schlumberger Gelled Acid DGA100	Thickened inhibited 15% HCl.	Carbonate reservoirs (especially older wells) where wider and deeper penetrating fractures are needed (80° to 250°F).	Acid Fracturing; reactive stages in DUOFRAC* II treatments.	Exceptional fluid-loss control and improved etch patterns; suspends and removes silts and solids with spent acid returns.
DGA200	HCl thickened up to a maximum of 28%.	Low-temperature carbonate reservoirs.	Acid Fracturing; Formation Cleaning of Fissured Reservoir, DUOFRAC II treatments for low-temperature well (150°F).	Retarded reaction rate; reduced leakoff, low viscosity when spent for good cleanup; liquid additive gels up to 28% HCl.
DGA300	HCl thickened up to a maximum of 28%.	High-temperature carbonate reservoirs.	Acid Fracturing; Formation Cleaning of Fissured Reservoir, DUOFRAC II treatments for high-temperature well (300°F).	Retarded reaction rate; reduced leakoff, continuous- or batch-mix applications; stable at high temperatures. Gels up to 28% HCl.
Foamed X	Stable inhibited HCl and foam; 55% to 85% foam quality.	Low-pressure, low-permeability carbonate reservoirs (80° to 250°F).	Acid Fracturing and Formation Cleaning of Fissured Reservoir.	Improved leakoff control and well cleanup with more efficient return of treating fluids.
Retarded Acid 8	Inhibited blend of HCl and acetic acids. 55% to 85% foam quality.	High-temperature carbonate reservoirs where high acid concentrations and long exposure times are required (80° to 300°F); carbonate reservoirs (80° to 250°F).	Acid Fracturing; Solvent for Carbonate Deposits; Wellbore Cleanup Fluid. Cleaning of Fissured Reservoir.	Retarded reaction rate; concentration equivalent to 20.2% HCl. Well cleanup with more efficient return of treating fluids.
Retarded Acid 8	Inhibited blend of HCl and acetic acids.	High-temperature carbonate reservoirs where high acid concentrations and long exposure times are required (80° to 300°F).	Acid Fracturing; Solvent for Carbonate Deposits; Wellbore Cleanup Fluid.	Retarded reaction rate; concentration equivalent to 20.2% HCl.

Table 2–Formulation for carbonate matrix acidizing

1.8.3 Petrophysics

The type and distribution of porosity have a strong influence on the extent of damage and on the penetration of the acid. Reservoirs with a high matrix permeability can be severely damaged by invasion of solid particles. If high permeability is due to large, inter-connected pores, short and very wide wormholes will form.

When massive carbonate formations are en-countered, they are often very compact and very hard. Their natural matrix porosity and permeability are usually very low. When tectonics generates earth movements, these brittle (nonplastic) rocks will crack rather than deform, and fractures are created In this case, most of the reservoir porosity is formed by the fissures. Oil or gas migrates in from the original source rock.

In fractured rocks, damage by solid particles occurs in the fractures. An acid treatment enlarges the fractures and allows cleanup to occur. An MSR treatment is ideal for this application because of its fines-suspending properties. [3,8]

1.9 Organization of the Decision Tree

The selection tree shown in Figure 2 considers carbonates with matrix and fracture damage. (Carbonates with damage in natural fractures are treated like carbonate cemented sandstones damaged in fissures)

Treating fluids are separated by temperature and range of application in Figure 2. At high temperatures, organic acids or NARS are used. Various acid systems exist for treating formations at low to moderate temperatures (Table 2). • Hydrochloric acid diluted with alcohol is recommended for treating producer wells (prevention of water blocks) up to 250°F (121°C).

• Intensified Acid XX or MSR is recommended to dissolve silicates mixed with carbonates up to 300°F (150°C). • DAD is used to dissolve insoluble organic material and carbonate rock.

• Foamed acid is recommended in formations having big pores (or vugs), and when diversion and fast cleanup (in low-pressure wells) are required.

• Gelled acids can also be used to clean fissured or vuggy formations at matrix rates; increased viscosity provides better control of fluid leakoff, and facilitates fines suspension and cleanup.

Additives must be used in acid formulations to avoid precipitation of iron hydroxide and enhance formation cleanup. [3,8]

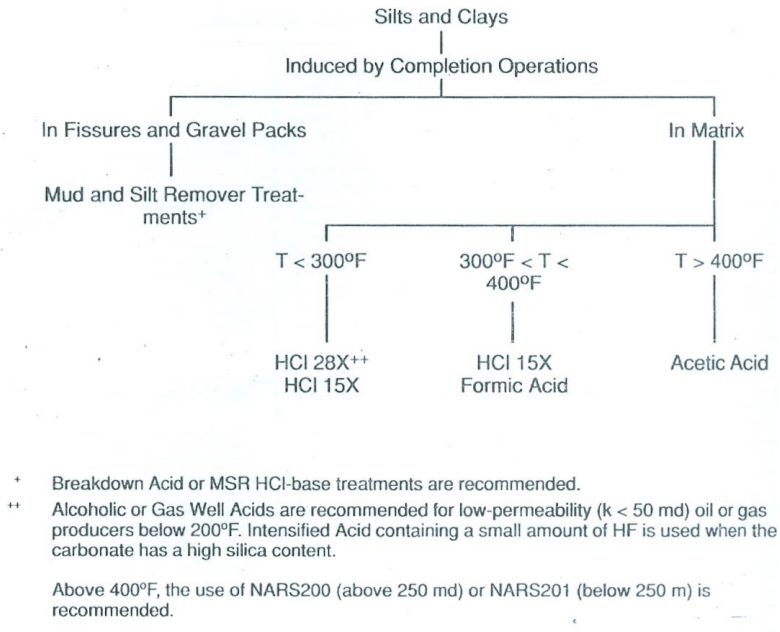


Fig 2 – Treatment fluid selection in carbonate acidizing induced by completion operation [8]

1.10 Well Preparation

Injection fluids must leave surface containers, travel through conduits, enter a wellbore, and pass through the perforations into the formation so that the solvent can react with the damaging solids. Each of these components through which the fluid travels must be properly cleaned before pumping acid into the formation.

Surface containers must be cleaned before being filled with acid. The best containers are rubber lined and clean of any former components before the acid and additives are added to the tank. Surface lines through which the acid is pumped should be cleaned with acid before the treatment. A small amount of acid can be flushed through the lines and into the waste pit before final hookup for the well treatment. This may be accomplished in the step for cleaning well tubing.

Fig. 3 shows the characteristics of acid being pumped down tubing in a well. Pumping acid through tubing removes solids deposited on the pipe surface. Acid-insoluble solids like pipe dope,

paraffin, asphalt, and gypsum or barite scales may plug the perforations or fill the wellbore. Acid-soluble solids like calcium carbonate may just spend the acid, whereas iron oxide or iron sulfide may precipitate in the formation as the dissolving acid spends on other acid-soluble minerals. Either acid cleaning the tubing and reversing to a surface pit or bypassing the production tubing with an acid-cleaned concentric tubing string will prevent perforation plugging from tubing deposits. [1,9]

For high-pressure reservoirs, acid may be pumped down the tubing close to the bottom and then flowed back to the surface waste pit. A small amount of acid pumped into the tubing removes all the rust scale and excess pipe dope. If the reservoir pressure will not hold the acid hydrostatic column, foamed acid may he used to clean the tubing. If the production tubing cannot be cleaned properly, it should be bypassed by using a concentric tubing string to pump the acid.

An extra advantage of using a concentric tubing string is to circulate brine to clean out the rathole below the perforated interval before acid injection. When there are deep ratholes with accumulated sludges, wellbores should be circulated to surface pits. Injection wells may have accumulated corrosion deposits and/or bacterial slimes. Old producing wells may have loose scale deposits, hydrocarbon solids, or produced fomiation fines.

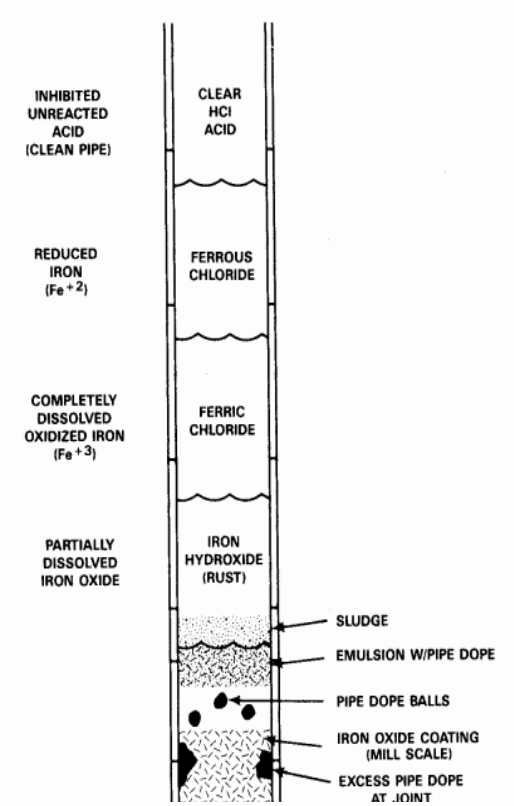


Fig 3 – Tubing cleaning with acid [1]

1.11 Acid Placement and Coverage

A leading cause of unsuccessful acid treatments is failure to contact all the damage with the acid. 26 Fluids pumped into a formation take the path of least resistance. In a typical treatment, most acid enters the formation through the least damaged or undamaged perforation tunnels. When this happens, it is easy to conclude that acidizing is very expensive and does not work well. But acidizing works well to remove damage if the type of damage is known and if the treatment is designed properly. A well-engineered acid treatment will not be effective unless it is properly placed. Numerous methods help control acid placement. Selection is based on wellbore hardware, formation characteristics, and field experience. [1,7]

Chapter 3: Acid Treatment Evaluation

Stabilized productivity may be analyzed when formation permeability is known. Standard analysis techniques are available for a semisteady-state flow analysis.6° Pressure buildup tests can also be run after acid cleanup and after production stabilizes. Postacidizing precipitation is implied if the acid actually removed damage during injection, but production remained unchanged or decreased. Acid precipitates that plug the formation often are detected by produced fluid sampling. Transient pressures during the acid treatment may be analyzed for formation permeability and wellbore condition. An example of analyzing acid injection pressure transients is presented by McLeod and Coulter. 141 The previous analysis is corrected as recommended by Earlougher51 and Kazemi.142 Two injection pressure buildups were analyzed before and after acidizing. These two pressure transient examples are plotted in Figs. 4 and 5. Table 3 gives pertinent data, and Tables 4 and 5 show the calculations and results. Before the acid treatment, the data in Fig. 4 indicate that permeability was 16 md and the skin was +15. After acidizing, the data in Fig. 5 were analyzed to determine that the formation permeability was 19 md and the skin was reduced to — 2. Stabilized water injection of 1,570 B/D [2494.7 m^3/(11 was obtained at a surface pressure of 2,000 psi [14 MPal when the well was connected to the lease water injection system. Table 5 presents the calculated stabilized injection rate at a surface pressure of 2,000 psi [14 MPal using the data provided from the acid treatment pressure transients. The calculated rate is 1,540 B/D [245 m^3] (11 water, which is an unusually close match. Most data evaluated from acid treatment records provide permeability and skin estimates within 10 to 25% of actual values, which is usually sufficient for evaluating the success of an acid treatment. Obviously the data in this example show the large change in wellbore condition before and after acidizing. The injectivity increased about five-fold by this acid treatment. To use transient analysis techniques on acid treatments, accurate data must be obtained. This requires close supervision by both the service company and the operating company. Even better records are provided by a recorder that measures both rate and pressure vs. time. [1,5,10]

Assumed Well Data	
μ	= 1 cp,
ϕ	= 0.25,
c	= $(10)^{-5}$ psi^{-1},
B	= 1.0, and
r_w	= 0.4 ft.
Buildup Data	
Before acidizing:	
h	= 27 ft,
q	= 0.35 bbl/min or 502 B/D
m	= 190 psi/cycle, and
k	= 15.9 md.
After acidizing:	
q	= 2 bbl/min or 2,880 B/D,
m	= 910 psi/cycle, and
k	= 19 md.

Table 3 – Acid treatment evaluation data [1]

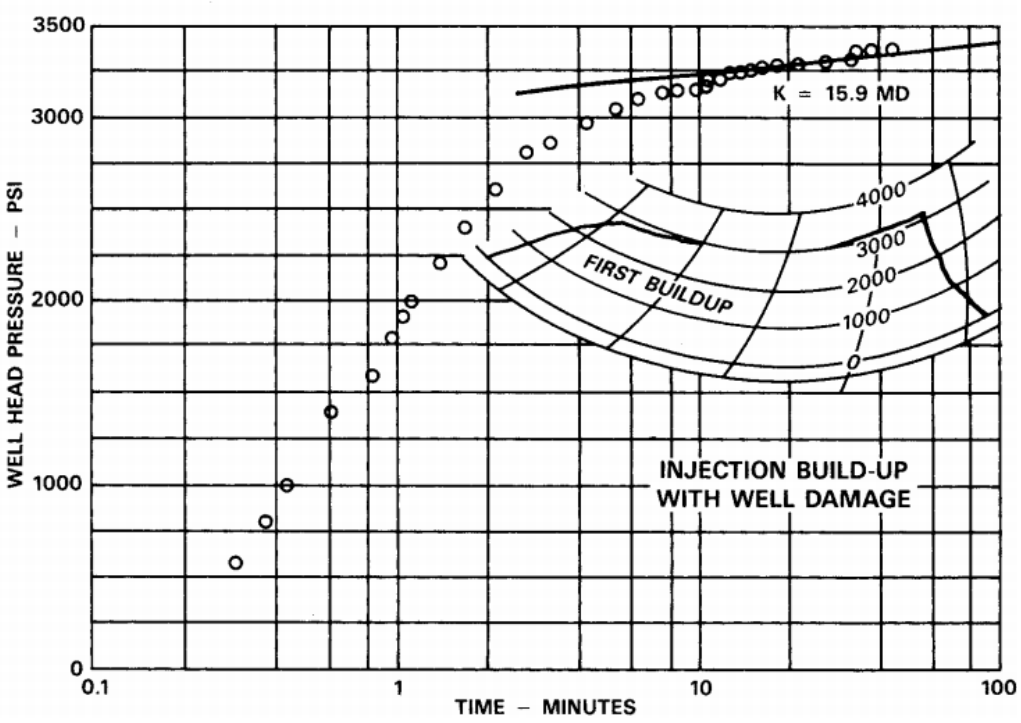


Fig 4- Injection pressure buildup with wellbore damage [1]

$$kh = \frac{162.6\,qB}{m}$$

$$= \frac{162.6(502)(1)(1)}{190} = 430 \text{ md-ft}$$

and

$$k = kh/h = 430/27 = 15.9 \text{ md.}$$

$$S = 1.151\left(\frac{p_{1hr} - p_w}{m} - \log\frac{k}{\phi\mu c r_w^{\,2}} + 3.23\right)$$

$$= 1.151\left[\frac{3{,}400 - 0}{190} - \log\frac{15.9}{(0.25)(1)(10)^{-5}(0.4)^2} + 3.23\right]$$

$$= 1.151(17.89 - 7.60 + 3.23)$$

$$= 15.6.$$

Table 4- Analysis before acidizing[1]

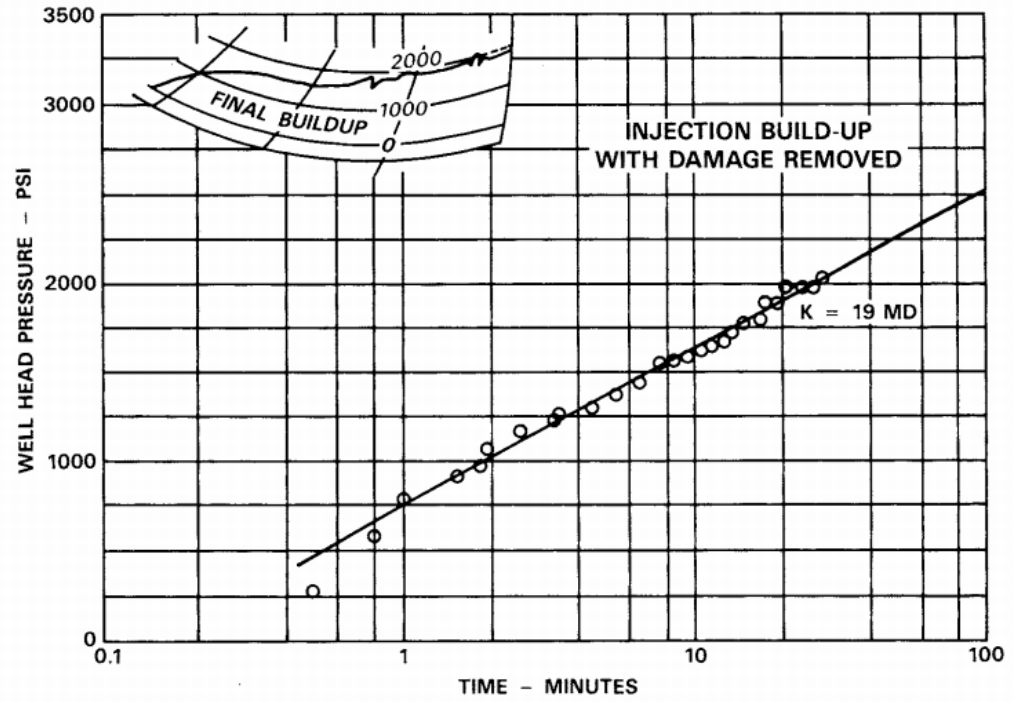


Fig 5 – Injection pressure buildup with damage removed [1]

$$kh = \frac{162.6\,q\mu B}{m}$$

$$= \frac{162.6(2{,}880)(1)(1)}{910} = 514 \text{ md-ft}$$

and

$$k = \frac{514}{27} = 19.0 \text{ md.}$$

$$S = 1.151\left[\frac{2{,}375 - 0}{910} - \log\frac{19}{(0.25)(1)(10)^{-5}(0.4)^2} + 3.23\right]$$

$$= 1.151(2.61 - 7.67 + 3.23)$$

$$= 1.151(-1.83) = -2.1.$$

Table 5- Analysis after acidizing[1]

Chapter 4 : Modeling the Carbonate acidizing

Carbonate acidizing is more difficult process to predict than sandstone acidizing because, despite the chemistry of the process being much simpler than that of sand stone acidizing, the physics is decidedly more complex. In sandstone, the surface reaction rates and slow and a relatively uniform acid front moves through the porous medium. In carbonates, surface reaction rates are very high, so mass transfer often limits the overall reaction rates, leading to highly nonuniform dissolution patterns. [8]

Often, a few large channels, called wormholes, are created, such as shown in Fig.6, caused by the nonuniform dissolution of limestone by HCl in a linear core flood (Hoefner and Fogler, 1988). The structure of these wormhole patterns will depend on many factors, including (but not limited to) flow geometry, injection rate, reaction kinetics, and mass transfer rates. For example, Fig 7 shows a casting of wormholes created by radial flow of water through plaster (Dacord and Lenormand, 1987); this wormhole pattern is much more branched than that shown in Fig 6 and, clearly, the amounts of acid needed to propagate wormholes in these two systems would differ significantly.[8]

Since wormholes are much larger than pores in nonvugular carbonates, the pressure drop through the region penetrated by wormholes will be insignificant. Thus, in matrix acidizing, knowledge of the depth of penetration of wormholes allows a prediction of the effect of acidizing on the skin effect. Wormholing is also very significant in acid fracturing, as it will increase fluid loss rates, limiting the penetration of acid down the fracture. Thus, to predict acidizing results in carbonates, the physics of wormhole growth be described. This inherently unstable process is not understood completely, but considerable progress has been in recent years. [8]

Fig 7-Wormholes created by water[8]

Fig 6- Wormholes created by acid[8]

1.12 Network Simulation

Our numerical simulations have been carried out on a square grid of pores (up to 80x80), with the injection along one side (linear flow) or at a corner (quarter of a radial flow). The radii of the pores were chosen randomly to obtain the final required distribution. The flow in each pore was assumed to obey Poiseuille's law. The dissolution reaction was modeled by the enlargement of the pores according to a law derived from the solution of the diffusion equation in a capillary. No pore collision was allowed in these simulations. The accurate numerical resolution of the system of coupled equations allowed us to get quantitative results, particularly the behavior of the injection pressure vs. time during constant-rate injection. Further details of the simulator appear elsewhere.[2]

1.12.1 Linear Case

In all the experiments, the pressure decreased linearly with respect to time, as illustrated in Fig. 8 (the initial and final parts of the curve are discussed helow). This is consistent with characterizing the wormhole pattern by a unique equivalent length, L_e, so that there is no pressure drop from the injection face up to the distance Le and for distances greater than L_e, we can use Darcy's law:

$$p(t)=\frac{\mu q}{k\pi r_o^2}[L-L_e(t)]. \qquad \text{..... (1)}$$

The linear decrease of pet) vs. t means that Le has the form $L_e=L*t/t_o$, where t_o is a constant (corresponding to the time at breakthrough). Therefore, we can define a wormhole growth velocity, V_{wh}, as dL_e/dt. A better variable is in fact the dimensionless wormhole growth velocity, V_D, which is V_{wh}/V_C, where V_C is the velocity of the front in the case of total rock dissolution (which is achieved for very low flow rates, as discussed below). It is straight forward to calculate that

$$v_C=\frac{N_{ac}q}{\pi r_o^2\phi}, \text{ with } N_{ac}=\frac{\phi CM}{\beta(1-\phi)\rho} \qquad \text{..... (2)}$$

where N_{ac} is the acid capacity number for a totally soluble porous medium.

It has found that V_D is independent of N_{ac} but decreases with the flow rate according to its cube root: $V_{D\alpha}q^{-1/3}$ as illustrated in Fig. 9 (the different symbols correspond to experiments with different N_{ac}). This behavior has been observed to hold between two limits.

1. At very low flow rates, all the rock close to the injection face is dissolved before some reactive fluid can enter the porous medium. The dissolution pattern is compact (no wormholes); we shall refer the dissolution pattern is compact (no wormholes); we shall refer to this case as compact dissolution. We determined that the Peclet numbers ($N_{Pe}=q/Dr_o>$ with the sample radius, To, as the characteristic length) for this domain were always lower than unity.
2. At high flow rates, an induction period and a discontinuity at the breakthrough appear on the pressure curves and become more and more important as the flow rate increases (Fig. 1). Physically, these two deviations from the linear behavior correspond to the distance between the tips of the wormholes and their equivalent length.[2]

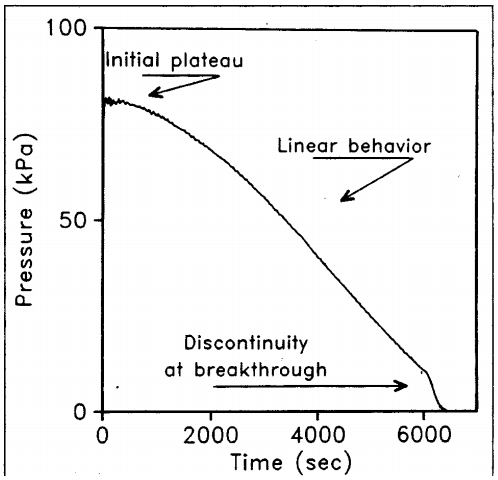


Fig 8- Linear- typical pressure curve[2]

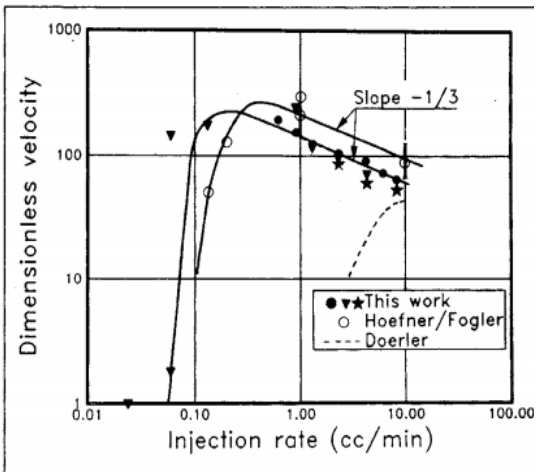


Fig 9- Linear-dimentionless wormhole velocity vs. flow rate[2]

1.12.1.1 Numerical Simulations

The effects of injection rate and pore-size distribution width have been studied. As the flow rate is increased, the pattern goes from stable (compact) to unstable (wormholes) and finally becomes homogeneous. Reducing the width of the pore-size distribution has a similar effect: the width of the acidized channels increases (Fig. 10) and the medium becomes more homogeneously etched at constant q. All the pressure curves (Fig. 11) display a linear behavior after an initial plateau, the importance of which varies with the conditions.[2]

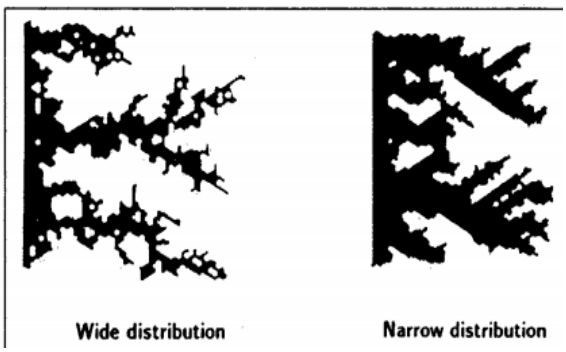


Fig 10- Effect of the width of the pore-size distribution [2]

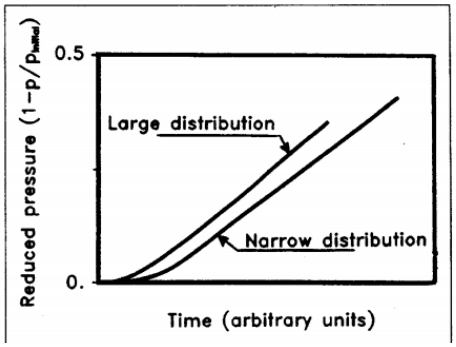


Fig 11- Pressure curve for displacement [2]

1.12.1.2 Interpretation

The dependence of V_D on $q^{-1/3}$ can be interpreted qualitatively by a capillary model.

1. For long samples, there is always one main wormhole that takes all the flow. We model it as a capillary.
2. We make the analogy with heat transfer in the same geometry. The total flux of heat to the wall of a given length of capillary is equal to the mean value of the Nusselt number. For low Reynolds numbers, the Nusselt number is known to depend only on the Peclet number to the power 1/3.
3. Concerning the convectional mass-diffusion problem, one would expect that the amount of reaction in a portion of capillary depends only on the Peelet number to the power 1/3. The amount of reactive fluid left for propagating the dissolution front ahead of this distance will then depend on $N_{Pe}^{-1/3}$.); i.e., one would expect $V_D \alpha q^{-1/3} D^{1/3}$).

Thus, this simRle model predicts that we should get the dependence $V_D \alpha D^{-1/3}$· Fluid viscosity and system temperature are implicitly included in this law through their effect on D. This prediction requires an experimental verification, which is in progress; however, preliminary results are compatible with this behavior. We know that

$$v_D = \frac{v_{WH}}{v_C} = aN_{\mathrm{Pe}}{}^{-1/3}, \text{ with } N_{\mathrm{Pe}} = \frac{q}{Dr_o} \qquad \text{..... (3)}$$

where a is a dimensionless constant determined experimentally.

($a = 140$ for 2.54-cm [1-in.] -OD samples).

$$L_e(V) = V\frac{v_{WH}}{q} = V\frac{v_D v_C}{q} \quad \text{.....}$$

or

$$L_e(V) = \frac{aVN_{\mathrm{ac}}}{\pi r_o^2 \phi}\left(\frac{q}{Dr_o}\right)^{-1/3} \quad \text{.....} \qquad \text{..... (4)}$$

1.12.1.2.1 **Transition from Compact to Wormhole**.

It has been observed that for infinitesimal flow rates, the dissolution is controlled only by molecular diffusion; compact structures are expected (with a rough and maybe fractal surface, but only on a very small scale. These patterns are similar to that resulting from the displacement of a low-viscosity fluid by a high-viscosity one in a porous medium: plug flows are obtained that can be described by "anti-DLA" models. Quantitatively, the maximum flow rate compatible with this type of dissolution corresponds to a convection velocity, q/r_o^2, equal to the diffusion velocity, D/r_o. This is equivalent to a Peclet number $N_{Pe} = q/Dr_o$ on the order of unity.

1.12.1.2.2 **Transition from Wormhole to Homogeneous**.

The upper limit of the fractal behavior should correspond to flow rates so high that almost no dissolution has time to take place. A rough estimate of the distance necessary to get an appreciable dissolution is given by the distance between the very tip of the pattern and its equivalent length; if the sample is smaller than this "front thickness," the breakthrough will occur before any large channel has been created.

From our computer simulations and experiments, several parameters influence this distance.

1. It increases as the flow rate increases.
2. 2. It increases as the sample becomes more homogeneous. It has shown by varying the pore-size distribution in the network simulation (Fig. 10). In addition, laboratory experiments performed with natural rock samples do not display this intermediate zone, which is always visible in the highly homogeneous plaster.
3. It should also be affected by the kinetic parameters of the dissolution. Effectively, the transition from mass-transfer-limited to surface-reaction-limited dissolution takes place for values of the dimensionless kinetic parameter (N_{ki} =D/Kd for a first-order reaction) on the order of unity, where d is the thickness of the diffusion layer, which is a function of the flow velocity. At high velocities and at the pore level (d<pore radius), N_{ki} is maximum; therefore, the surface reaction may limit the kinetics (depending on the value of K). In this regime, the reaction rate is independent of the local velocity, and thus a homogeneous dissolution (similar to that obtained for sandstones) is expected. As soon as the pores are

sufficiently enlarged for N_{ki} to decrease below unity, however, flow instabilities are enhanced, leading to the creation of wormholes.[2,8]

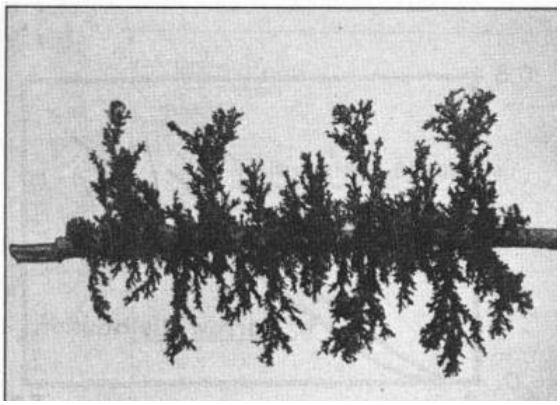
1.12.2 Radial Case

A similar approach was used to study the radial geometry. The fundamental difference between the radial and linear cases is that the equivalent pattern radius, r_e (calculated from the pressure curve and Darcy's law in radial geometry), does not grow linearly with time. In fact, we found that re($r_e \alpha t^{\alpha}$, with α=0.65±O.07. This value is significantly higher than 0.5, which is expected for uniform radial displacement and is characteristic of a fractal behavior (Fig. 12). The corresponding fractal dimension should be $d_f = l/\alpha$, which has to .be compared with the value directly measured on two-dimensional radial patterns, d_f = 1.6±0.1.

Fig. 13 displays the results of our study of the effect of the flow rate on the wormhole growth velocity. The dimensionless wormhole velocity (defined in a way similar to the linear case-i.e. , $V_D = V_{wh}/V_C$ with $V_C=N_{ac}q/\varphi\pi rh$) , calculated for a constant penetration equal to 2.54 cm [1 in.] , displays the same behavior as for the linear case ($V_D \alpha q^{-1/3}$) over at least two decades of flow rates. The Peclet number for radial flow is defined in a way similar to that for linear flow. The convection and diffusion velocities at the wellbore are on the order of q/hr_{wh} and D/r_{wh}, respectively, which yield N_{Pe} =q/Dh. We observed that the transition from compact dissolution to wormholes takes place for N_{Pe} also on the order of unity.

1.12.2.1 Numerical Simulations

Numerical simulations under radial conditions yielded patterns comparable to those obtained under linear flow , in regard to the effect of the flow rate (Fig. 14) and the sample homogeneity. In contrast, the pressure curves were different and displayed a linear behavior of the reduced pressure (1-P/ Po) vs. the logarithm of time (Fig. 15). The fractal dimension of the patterns (computed from the dependence of their mass vs. time) was found to be equal to 1.66.



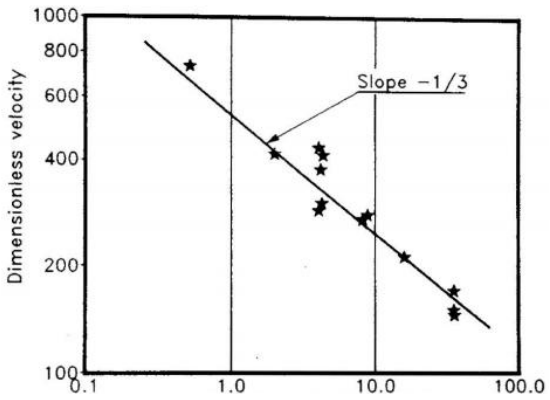


Fig 12– Radial- 3D distribution pattern [2] **Fig 13-** Radial- dimensionless wormhole velocity vs. flow rate [2]

1.12.2.2 Interpretation

All these results indicate that the fractal character is decoupled from the physical process of dissolution. This is fully consistent with the "universality" of DLA. Therefore, V_D obeys the law

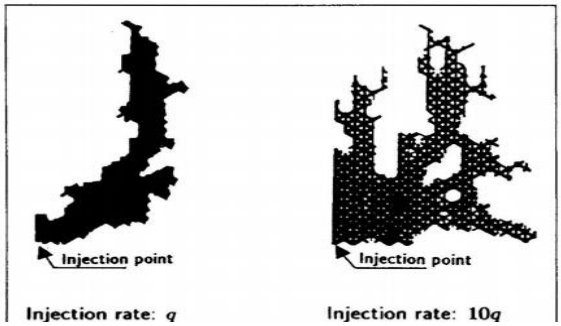
$$v_D = b r_e^{(2-d_f)} N_{Pe}^{-1/3}, \text{ with } N_{Pe} = \frac{q}{Dh} \qquad \text{..... (5)}$$

Where

b = constant,

r_e = penetration, and

N_{pe} = Peclet number for a radial geometry.



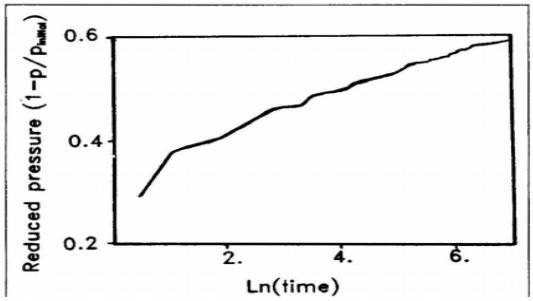


Fig 14 – Typical distribution patterns[2] **Fig15** – Typical pressure curve[2]

We determined experimentally that b = 1.7 * 10^4 m^{df-2} [1 * 10^4 ft^{df-2}]. The penetration achieved with a given volume of fluid, V, is

$$r_e(V) = \left(\frac{bN_{ac}V}{\pi h \phi} N_{Pe}^{-1/3} \right)^{1/d_f} \quad \text{..... (6)}$$

Eq. 8 assumes implicitly that the fluid is injected along the axis of the sample; i.e., we neglect our starting with a finite wellbore radius r_{wh}. We can, however, include it with a simple assumption: that the effect of a finite wellbore radius is equivalent to pumping an extra volume of fluid equal to that necessary to get a penetration equal to r_{wh} (according to Eq. 6).

The skin factor $s=(k_o/k-l)\ln(r/r_{wh})$ can then be calculated. Our equivalent radius, r_e, is defined as the radial distance over which there is no pressure drop-i.e., $k(r<r_e)=\infty$. Thus, the skin factor is just equal to $-\ln(r_e/r_{wh})$:

$$s = \frac{1}{d_f} \ln \left(\frac{bN_{ac}V}{\pi h \phi r_{WB}^{d_f}} N_{Pe}^{-1/3} + 1 \right) \quad \text{..... (7)}$$

with d_f = 1.6 and b = I. 7 * 10^4 in SI units. Other assumptions could have been used to account for the finite wellbore radius (such as replacing r_e by $r_e - r_{wh}$). Their effect becomes marginal as soon as the volume is large enough.

It was using the equivalent length of the wormholes as a unique characterizing parameter. This parameter describes the flow properties of the whole pattern, and there is no need to know the exact number of wormholes and their size. In addition, the dimensionless value V_D represents the actual penetration rate compared with that obtained under compact dissolution; it is the best measurement of the beneficial role of wormholes.

The only drawback of this approach is that for the linear ID case (in which case the pattern is not fractal), the side branches do have an importance concerning the flow properties, which is not accounted for in Eq. 3. As a consequence, Eq. 5 is unable to predict correctly the effect of the sample radius, ro. The dependence described ($L_e \alpha r_o^{-5/3}$) is not verified by the experiments; in fact, we observed the dependence $L_e \alpha r_o^{-1}$. A more in-depth discussion of this point will appear in a

forthcoming paper. This drawback is of no practical importance, however, because the actual geometry of matrix treatments is never linear 1D. This drawback does not exist for the other geometries (radial or linear 3D) because the side branches are at the basis of the fractal character and their effect is therefore implicitly described by the fractal dimension, d_f.

Eq. 9 has been used in an actual treatment. From the treatment and well parameters and the analysis of the pressure response during the job, Lietard and Daccord calculated that the skin decreased effectively as -αIn(V) with α =0.7 and that the absolute value of skin at the end of the first stage (about 5 m^3 [1,320 gal] of 15% Hel) was -0.85. Using Eq. 7, we calculated a theoretical skin decrease of -0.76, which is in excellent agreement with the above value.[2]

1.13 Another method for Simulation

Recently. Pichler et al. (1992) presented stochastic model of wormhole growth, based on diffusion-limited kinetics and incorporating the randomness of diffusion-limited aggregation (DLA) models. This model predicts the branched wormhole structures found in carbonate acidizing, as shown in Fig. 16. With a large diffusion rate the wormhole branches are thick, while lower diffusion rates lead to predictions of thinner wormhole branches. This difference illustrates the transition in wormhole patterns from a pattern near to compact dissolution to a more dominant wormhole structure. Pichler et al. also included permeability anisotropy, Permeability heterogeneity, and natural fractures in their model and illustrated how these factors bias the wormhole patterns created. With further development, stochastic models such as this one show great promise for predicting wormhole propagation quantitatively.[8]

Another approach to predicting volume of acid required to propagate wormholes a given distance is to assume that the acid will dissolve a constant fraction of the rock penetrated. When only a few wormholes are formed, a small fraction of the rock is dissolved; more branched wormhole structure dissolve larger fractions of the matrix. Defining η as the fraction of the rock dissolver in the region penetrated by acid, for radial flow it can be shown that.

$$r_{wh} = \sqrt{r_w^2 + \frac{N_{Ac} V}{\eta \pi \phi h}} \qquad \text{………………………………..….. (8)}$$

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

$$\eta = N_{Ac} P V_{bt} \quad \text{..... (9)}$$

where PV_{bt} is the number of pore volumes of acid injected at the time of wormhole break-through at the end of the core. This approach is equivalent to assuming that a fixed number of pore volumes of acid is needed to propagate wormholes a given distance.

The model presented here (the volumetric model) is an empirical one. If the wormholing efficiency is obtained from radial core floods, it should accurately predict wormhole in a well treatment where the flow is radial, at least for wormhole propagation to the same distance as that tested in the core flood. If linear core floods are used to measure n, the wormhole propagation in radial flow will probably be somewhat overestimated.[8]

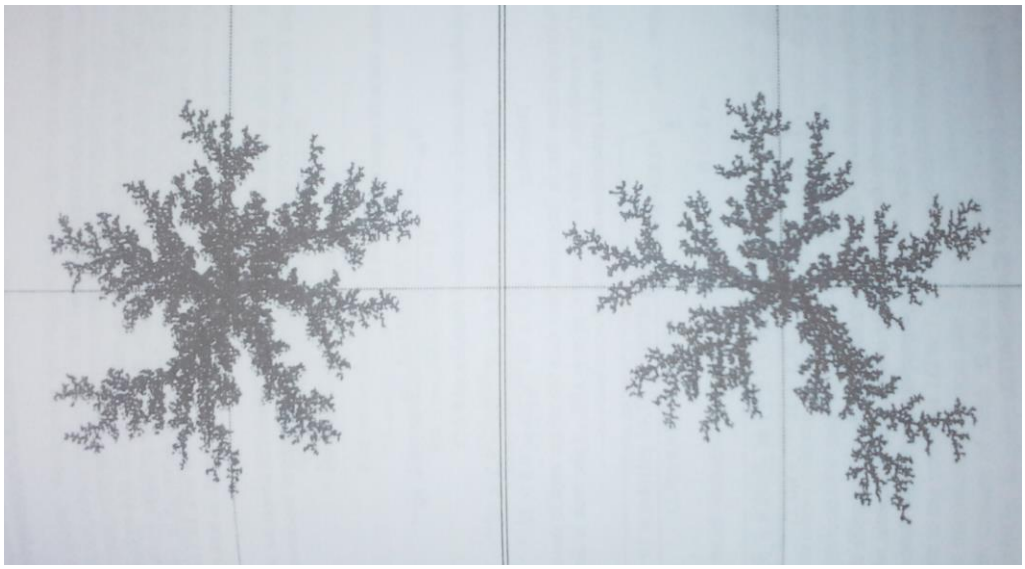


Fig 16- Wormholes patterns generated by a stochastic model [8]

Chapter 5: Software

1.14 StimCADE (Stimulation Computer-Aided Design and Evaluation)

StimCADE (Stimulation Computer-Aided Design and Evaluation) is an unified WINDOWS software application developed jointly by AFlCO and Dowell. The program is intended for use by production and operations engineers for improved matrix treatment design, QC, and analysis. The StimCADE program involves the integration of technology from ARGO and Dowell into modules making up a comprehensive matrix stimulation design and analysis engineering tool.

The program provides:

1. Complete treatment fluid sequence recommendation based on reservoir lithology, well condition, and expected damage mechanisms.
2. Quantitative pumping schedule specification, including fluid volumes, number of diverter stage, and injection flow rates based on target fluid invasion depth or skin reductions.
3. A comprehensive fluid reservoir simulator capable of modeling multi zone diversion effectiveness, used foe prediction flow rate and skin evolution throughout the proposed treatment.
4. A geochemical module, useful for checking for treatment fluid/reservoir rock incompatibilities.
5. A suite of standalone tools/utilities, used for production forecast prediction, calculation of perforation critical drawdown for sand production, geochemical scale prediction, ball sealer optimization, and foam diversion design.
6. Three knowledge base advisors, available to aid in candidate selection, formation damage identification, and treatment fluid selection.

StimCADE application are presented in module which are divided into five groups under the main StimCADE pull-down menu. The grouping are general Input, Advisors, Simulation Modules and design Module Tools.

An overview of the methodology utilized in StimCADE may be seen in Fig. 17.[11]

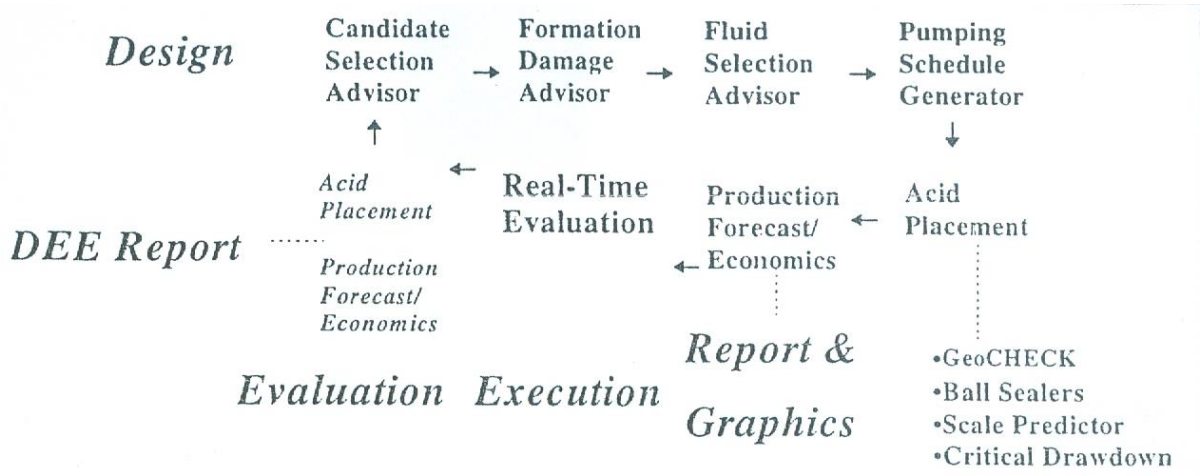


Fig 17- Methodology utilized in StimCADE [11]

Based upon experience, the Design Engineer can enter StimCADE at various levels. For example the non-expert can/should enter at the Candidate Selection Advisor whereas the "expert" may enter at the Pumping Schedule Generator or Acid Placement. The Advisors are used for candidate selection, formation damage identification and selection of fluid types and volumes. The design modules in StimCADE are used to optimize your fluid schedule based on skin evolution and fluid compatibility. A "first pass" pumping schedule (fluids, pump rates, volumes, diverter stages) can be generated. Using the Pumping Schedule Generator. The fluid compatibility is verified using a geochemical model. StimCADE also contains a suite of utility programs. The utility programs include calculations for critical drawdown, geochemical scale prediction and ball sealer optimization. The critical drawdown model predicts the sanding tendency of a reservoir for a given drawdown.[11]

On-site diagnostics and monitoring capability will allow re-design on location based on skin evolution. A step-rate diagnostic tool will be used to determine pre- and post–treatment permeability and skin. Post-treatment evaluation will utilize the Production Prediction Module determine the effectiveness of the stimulation design. Also Well File documentation is generated using the Customer Report and Graphics modules. It is believed that application of this Methodology will result in improved Matrix treatment success.[11]

1.14.1 Candidate Selection Advisor

The purpose of the Candidate Selection Advisor (CSA) is to provide a simple screening tool for the engineer to verify the suitability of a well for a matrix stimulation. An effective well treatment program starts with determining which wells will respond most favorably to the planned treatment. Candidate wells are typically those which have shown a decrease in production or injection. In the past experience has been relied on heavily in this decision. Standardizing the process of well selection may help improve treatment program success rates. The Candidate Selection Advisor (CSA) is a simple tool which attempts to do this. The engineer must examine well history, production/injection history, and well operating conditions when considering a well for stimulation. He must also consider whether a matrix or fracturing treatment is more appropriate. A flow chart that depicts the decision process found in the CSA may be seen in Fig. 18.[11]

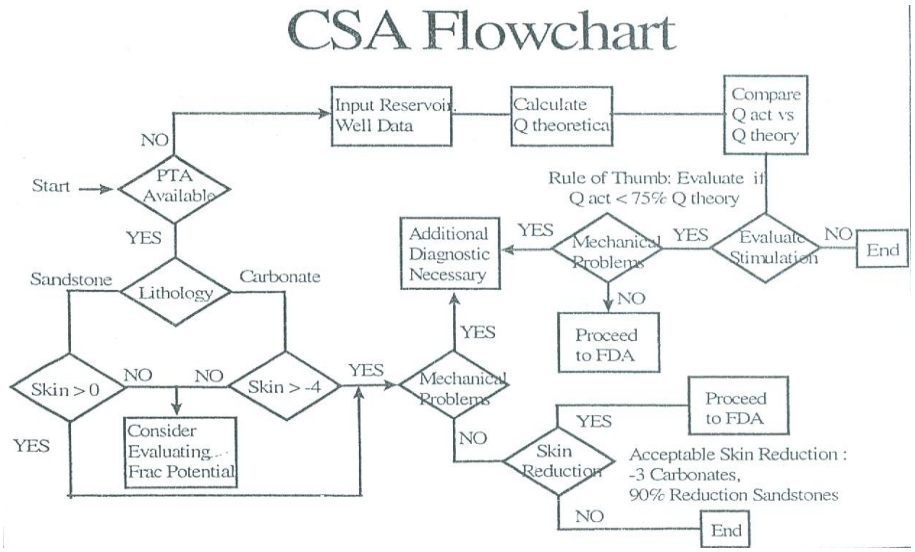


Fig 18- Candidate selection advisor (CSA) process [11]

The CSA knowledge base interrogates the engineer and uses a series of rules to determine the suitability of a well for matrix stimulation. It makes its determination based on pressure transient analysis results for the well or on the ratio of actual to theoretical flow rates. Consideration of possible mechanical problems is also built into the rules. The CSA knowledge base uses a simplified method of estimating theoretical reservoir flow. Rate is calculated using the Darcy flow equation assuming radial flow as shown below:

Oil ..... $q = \dfrac{2*\pi*k*h*(P_r - P_w)}{\mu*B_o*(\ln(re/rw)+s)}$, in oilfield units this translates to

$$q = \frac{7.082X10^{-3}*k*h*(P_r - P_w)}{\mu*(7.5+s)}$$

where
- k = permeability (md)
- h = net pay (ft)
- P_r = reservoir pressure (psi)
- P_w = flowing pressure (psi)
- μ = viscosity (cp)
- B_o = formation volume factor (defaulted to 1)
- (re/rw) = radial distance to external boundary/radius of well
- ln(re/rw) is estimated to be 7.5

Gas: ..... $q = \dfrac{T_s*\pi}{P_s*\mu*T} * \dfrac{k*h*\left(P_r^2 - P_w^2\right)}{\left(\ln(re/rw)+s\right)}$, in oilfield units this translates to

$$q = \frac{19.88X10^{-3}*T_s k*h*\left(P_r^2 - P_w^2\right)}{\mu*P_s*T_f(7.5+s)}$$, with the CSA assumptions, this is

$$q = \frac{5.39X10^{-2}k*h*\left(P_r^2 - P_w^2\right)}{(7.5+s)}$$

where
- k = permeability (md)
- h = net pay (ft)
- P_r = reservoir pressure (psi)
- P_W = flowing pressure (psi)
- P_s = standard pressure (defaulted to 14.5 psi)
- μ = viscosity (defaulted to 0.02 cp)
- T_s = standard temperature (defaulted to 487.3 °R)
- T_f = flowing temperature (defaulted to 620 °R)
- (re/rw) = radial distance to external boundary/radius of well
- ln(re/rw) is estimated

Comparison of actual rates to the computed theoretical is made. The engineer is then asked to determine whether further evaluation is warranted. One 'Rule of Thumb'cutoff point says that the well needs stimulation if the actual rate is less than 75% of the theoretical. This cutoff should only be used as a gross indicator since the theoretical rates do not include effects due to production tubulars or separation equipment.[11]

1.14.2 Formation Damage Advisor

The Formation Damage Advisor (FDA) provides a systematic approach for the user to consider possible damage mechanisms which might be affecting a well.

Determining the damage mechanism affecting well productivity/injectivity is the most important step in designing an effective matrix treatment. Formation damage can occur due to a variety of reasons, but is most typically associated with partial plugging near the wellbore. The plugging can occur due to solids moving within the porous medium, precipitates produced by changes in the chemical or physical state of the reservoir, or even through changes in the relative permeability of the rock matrix in all cases, the formation permeability is reduced and production or injection declines. Matrix treatments target the removal or bypassing of near wellbore damage. Treatment fluid recommendations are highly dependent on the type of damage to be addressed.

The Formation Damage Advisor (FDA) is an expert system based on a knowledge base of rules pertaining to reservoir characteristics, production conditions, and various test results. The questions asked by FDA point out areas which the user should consider in trying to determine potential sources of damage to the well. The user will be asked general questions about the well, its completion, and the reservoir. He may be asked to indicate observations made about producing equipment, water cuts, or changes in flowrate. He may also be asked about various test results. If the test data is unavailable, the program may issue a warning if the data could be particularly important in determining damage type under the given conditions.

Because it is an expert system, the questions asked by the program are asked in random order based on the answers to previously asked questions. The software generates a list of possible damage mechanisms which could be affecting the well. It is possible to have more than one mechanism at work in the well.

The expert system knowledge base includes

- Rules specific to well operations. For example, for a wettability problem to occur, there must be no fill or scale observed in the production equipment.
- Rules specific to produced fluids. For example, scale cannot occur in a producing well unless it also produces water.

- Rules specific to well type. For example, the damage type "Emulsion Carryover" can only occur in injection wells.[11]

1.14.3 Fluid Selection Advisor

The purpose of the Fluid Selection Advisor (FSA) is to provide a mechanism for the user to obtain a treatment fluid recommendation based on damage type and well conditions. “Rules of Thumb” for acid recommendations have traditionally been used within the industry. These rules are generally area specific and based on past field experience. The FSA knowledge base is an attempt to quantify acid and diversion recommendation rules. The Fluid Selection Advisor is a knowledge base expert system with rules linking damage mechanism, reservoir lithology, well completion data, and downhole conditions. The user is lead through a series of questions about the well history and/or reservoir. The answers provided at each step affects the next level of questions asked. The software generates a fluid treatment recommendation which is output in spreadsheet form. A first pass estimate of total volume required for each fluid is also calculated. The fluid sequence generated by FSA also includes recommendations for diversion type if diversion is determined to be required. A flow chart showing how the FSA works may be found in Fig. 18.[11]

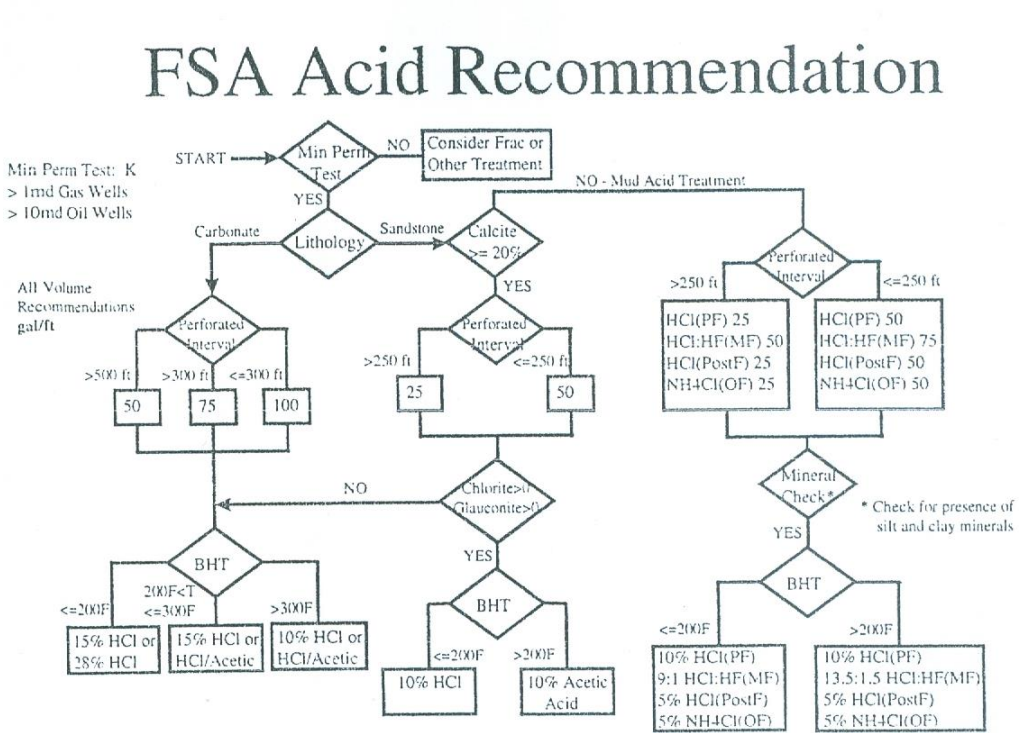


Fig 19- Fluid selection advisor [11]

The expert system knowledge-base includes:

- Rules linking damage type with possible treatment fluids. For example, treatment for an asphaltene or paraffin problem is the use of solvent.
- Rules for the determination of treatment volumes. Recommended volumes depend on lithology, type of treatment fluid, and treatment interval.
- Rules concerning single and multiple stage treatments. For example, carbonates are generally treated with single step HCI treatments, but sandstones can be treated using multi- stage mud acid treatments.
- Rules associated with bottomhole treatment temperatures. Since temperature effects chemical reaction rates, different acids are recommended for reservoirs of varying temperatures.
- Rules determining suitability of different diverters. For example, if N2 is going to be used during the treatment anyway, foam diversion is recommended for ail well types.

The included rules are a compilation of

- Real life experiences of industry experts
- Current published state-of-the-art rules and proven field practices
- Extensive laboratory work.
-

Recommendations for eighteen different damage types are supported by the FSA. The majority of these damages are corrected using an acid treatment. However, some damage mechanisms are treated with non-reactive fluids such as solvents. Certain damage categories have multiple treatment options. Volume recommendations can be made by FSA for only a single option at a time, so the user must choose an option when prompted. All options are considered equally effective.[11]

1.14.4 Treatment Design

The goal of the Treatment Design process is to provide the Design Engineer with the required tools to improve treatment results i.e. improved well performance. Currently, well treatment design and evaluation is highly dependent on local practice guidelines, individual expertise, or both; and is regarded as more art form than science. StimCADE emphasizes the scientific aspects of the process, enhancing the probability of attaining improved well performance. The treatment design process includes diagnostics and development of a pumping schedule to yield the most favorable economics. Of course the "design" must be operationally feasible and not create problems. Standalone tools including GeoCHECl<, Critical Drawdown, Scale and Ball Sealers complement the design process. Fig. 20 illustrates the Treatment Design process.

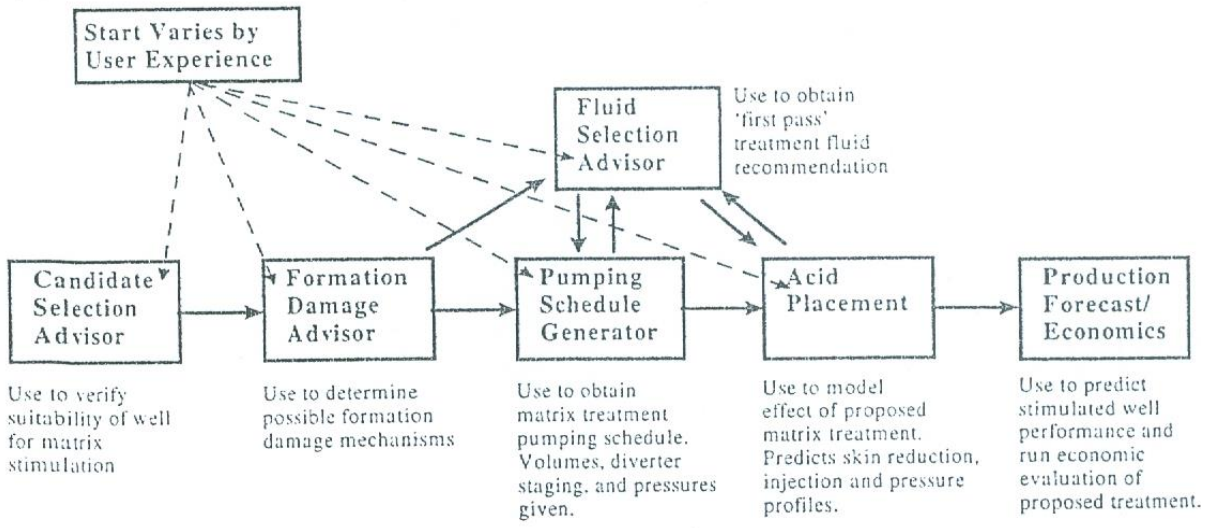


Fig 20- Treatment design[11]

Design steps include.

a. Diagnostics: The first step is directed at candidate selection. Wells are screened to determine the feasibility of using matrix treatments for stimulation. The goal is to select wells with the greatest potential for production increase and the lowest risk. The engineer must consider well history, production/injection history, and well operating conditions in making this determination. The Candidate Selection Advisor can be used to aid in this process. Possible damage mechanisms causing the production/injection decline must be characterized in order to select the proper fluid.

Again, the engineer must look at a multitude of variables including reservoir lithology, operating conditions, well type, previous stimulation history, and field observations to name a few. The Formation Damage Advisor can be a helpful tool in going through this data.

b. Fluid Selection: Treatment fluid selection recommendations are based on damage mechanism, lithology, and well conditions. The Fluid Selection Advisor is used in this process.

c. Pumping Schedule: A "first pass" pumping schedule (fluids, pump rates, volumes, diverter stages) is generated next using the the Pumping Schedule Generator. The initial fluid schedule can be user specified or proposed by the Fluid Selection Advisor. This schedule is optimized to meet specific objectives (i.e. skin value or fluid penetration) for each fluid type using a single phase reservoir model.

d. Numerical Simulation: The Acid Placement module, a 2D numerical simulator, is used to simulate damage removal, evaluate skin evolution, flow profile, and bottomhole pressure versus injection rate for the proposed pumping schedule. It incorporated pressure and flow rate computations, acid and diverter transportation, mineral species dissolution, diverter deposition and a porosity-permeability relationship/calculation. It allows a further optimization of the schedule to obtain the desired results in the most cost effective manner.

e. Production Prediction/Economics: Production performance is forecast, using the Production Forecast module and is based on initial/final skin calculations. Pay—out time and cash flow are determined allowing for economic justifications. Acid Placement is rerun as required to fine tune economics/production.[11]

1.14.5 Production Forecast Module

The purpose of the StimCADE Production Forecast module is to predict well performance and to calculate treatment economics. The StimCADE Acid Placement simulator will show the decline in skin during a proposed acid treatment. However, the bottom line question for the engineer is always, how this will affect the well performance (production or injection rate). Therefore, it is very important to provide a tool that will allow him to calculate the rate change associated with the skin differential. He should also be able to provide simple economic justification of any planned acid treatment. This is accomplished using Production Forecast.

Production Forecast determines well rates using semi—analytic pressure and rate transient solutions. By using dimensionless pseudopressure and pseudotime, developed for pressure transient well test analysis, the diffusivity equation for flow through porous media can be described using a linear equation. These equations can be solved analytically rather than by using a numerical simulator. This simpler solution runs much faster and consumes fewer computational resources. They have also been shown to be accurate during transient flow. This is particularly important when trying to determine the economic payout time for a well treatment. The model used in StimCADE allows for analysis under 3 different outer boundary conditions, infinite acting, no flow, and constant pressure. The user can make his prediction based on constant sandface (bottomhole) pressure or constant wellhead pressure (this option is still under development). He may consider skin either before treatment, after treatment, or both in his prediction.[11]

Assumptions used in the model include, a single fluid, constant porosity, and single layer reservoir. Production/injection rates are calculated for the primary fluid. Rates for other fluids are based on user input water-oil-ratio (WOR), gas-water-ratio (GWR), and gas-oil-ratio (GOR) values. The semi-analytical solutions do consider nonlinear fluid properties. They are an improvement over previous solutions that assume constant system compressibility and constant fluid viscosity. Pressure effects of production separators is also considered. The economics portion of the module allows evaluation of cost versus expected revenue. Costs which can be considered include treatment cost, operation costs, cost of money, applicable taxes, and any other auxiliary costs. The program also allows user input of produced product price, price adjustment factors, and a treatment chance factor. Various financial indicators are determined based on the input costs and predicted production rates. The calculated financial parameters include:

- ROR - rate of return
- ROI - return on investment
- NPV - net present value
- Payout (days) - for investment only
- Payout (days) - for investment plus interest
- Unit cost - investment divided by incremental production

Cumulative production and daily rates are output in the Summary Report spreadsheets. The calculated financial indicators can also be seen here. The more comprehensive Engineering Report

also includes input parameters, pressure data, and an estimate of initial oil in place. Plots of the predicted production rates, cumulative production, and predicted average reservoir pressures are automatically generated.[11]

1.14.6 Critical Drawdown Module

The critical drawdown program predicts the maximum sand-free bottomhole flowing pressure for a given well and the minimum reservoir pressure prior to subsidence. The primary components of the method are prediction of rock strength, calculation of maximum drawdown for perforation stability, and calculation of reservoir failure. This model was developed in response to a need for predicting perforation and reservoir failure in offshore wells in the Gulf of Mexico. The application has found utility for determining the need for gravel packing, predicting borehole stability, designing frac lengths for "frac and pack" application sand evaluating pore collapse and reservoir subsidence problems. The model has been validated in wells in the gulf coast of the US, Alaska, China, North Sea and Indonesia.

Formation sand is produced when the combined effects of fluid drag and near-wellbore stresses cause dis-aggregation near the perforation. lndividual grains of sand are detached from the matrix followed by bridging which occurs when a stable sand-arch is formed at the perforation tip. This zone or arch is a dilated region with enhanced permeability and porosity but impaired strength. At relatively low flow rates, fluid drag does not affect arch stability, but as flow rate increases, drag forces are sufficiently high to remove sand particles from the arch, thereby de- stabilizing sand-bridges. If such drag forces are too high, no sand arches are formed and sand production continues. The perforation stability calculation provided in the critical drawdown module predicts the differential pressure across the sand face at which the perforation will start to fail and produce sand. Reservoir stability is adversely affected when the effective formation overburden stress is higher than the formation strength. As reservoir pressure declines, formation shear stresses increase if the reservoir shear stress increases to the point where the formation fails, the allowable drawdown pressure at the perforations can become very small. The reservoir stability calculation estimates existing and future rock stresses as the reservoir depletes. These calculated stresses are compared to the failure criterion of the reservoir rock to determine whether gross shear failure will occur during the life of the well, and if so, at what reservoir pressure. Reservoir mechanical

properties can be estimated from Sonic Log data using correlations or can be determined in the lab from core tests. The current program calculates the critical drawdown at a single point in the well. When selecting this point on a sonic log, look for an interval of high porosity, high sonic travel time and low shale volume. There are some limitations and assumptions associated with the model:

- Single phase flow in the well and does not account for wettability affects.
- The perforation tunnels are cylindrical cavities with spherical tips.
- That the formation is homogeneous, isotropic and infinite in extent.
- That the pore fluid is slightly compressible and that flow is laminar in oil wells andturbulent in gas wells.[11]

1.14.7 Scale Prediction Module

The purpose of this application is to bring together, in one module, a comprehensive scale analysis and prediction model that allows the user to predict mineral deposition in a variety of situations.

This model is the off-spring of a Gibbs free energy minimization technique used to predict scaling and formation damage in the Prudhoe Bay Unit waterflood. In conventional approaches the equilibrium constants used to determine species‘concentrations are limited to available equilibrium constants of certain reactions which are pre-defined. This approach limits the reactions occurring in a system which causes some reaction paths to be missed. By utilizing equilibrium calculations based on the Gibbs free energy of individual species, this model can create sets of independent reactions to represent all possible reactions occurring in a system. This arrangement allows reaction paths to form according to the species and elements existing in the system rather than the predefined reaction routes used in the equilibrium constant approach. There are several ways in which mineral scales can develop inside the wellbore. One way is by the introduction of fluids into the formation. For instance, if brine is used to "kill" a well, the kill fluid may be incompatible with formation brine. Due to a reaction between the brine components and elements already present in the well, mineral scales result. Scales may also form clue to changes in temperature and pressure as reservoir fluids are produced up the wellbore. Compounds that are soluble at bottomhole conditions may become insoluble as the temperature and pressure are reduced.

The Scale Predictor module uses Gibb's Free Energy Minimization calculations to forecast these reactions. The calculations are based on the following information entered into the program about the existing well conditions:

- Temperature
- Pressure
- Carbon dioxide content
- Ionic species found in the well.
- Ionic species found in any introduced fluids

The Scale Predictor module combines the various ions entered on the module's form and calculates the tendency to form scale based on each set of conditions that you enter. If the concentration of any compound exceeds its solubility in the well, a solid scale will form. Each of the above factors has the potential to influence whether or not mineral scales will develop.

The scale model currently identifies 8 scales.

$FeCO_3$ Iron carbonate

$CaCO_3$ Calcium carbonate

$MgCO_3$ Magnesium carbonate

$CaSO_4$ Calcium sulfate

$CaSO_4$ (2H2O) Gypsum

$SrSO_4$ Strontium sulfate

$BaSO_4$ Barium sulfate

FeS_2 lron sulfide

Presently, within the initial release of StimCADE, there are some limitations with the analysis of scale prediction. When a total dissolved solid concentration of 50000 ppm is exceeded the molecular activity correlation (Debye-Huckel) used in the model loses validity. The CO2 solubility correlation is focused on Prudhoe Bay conditions which are 190°F, 5000 psi and 13% CO2 in the gas phase. [11]

1.15 StimPT

The StimPT system is specifically designed to provide engineers with the most comprehensive tools for matrix acidizing treatment design and analysis. More than just another matrix acidizing simulator, practical utilization of actual treatment data is the central theme that separates StimPT for competing products. The use of real data offers engineers much better understanding of their well's response, with resulting procedures that reflect the reality of what is occurring in the reservoir, before, during, and after matrix acidizing treatments.

There are four made of operation providing matrix acidizing treatment design and analysis func1ions coupled with reservoir simulation These modes are described in detail in their respec1ive sec1ions in the Help documentation.[12

1.15.1 Relationship between StimPT Operation Modes

1.15.1.1 Acidizing Design

This mode is used to automatically generate a matrix acidizing treatment schedule. The program helps you select the proper fluids associated with the type of damage in the well, and then the proper pump schedule to achieve the required penetration depth without hydraulically fracturing the rock.[12]

1.15.1.2 Acidizing Analysis

This mode provides access to Carbonate and Sandstone acidizing models. You can run any of the models from job-design data (i.e., a treatment schedule), Stim.PT database data, or real-time data to evaluate skin reduction using bottomhole pressure matching.[12]

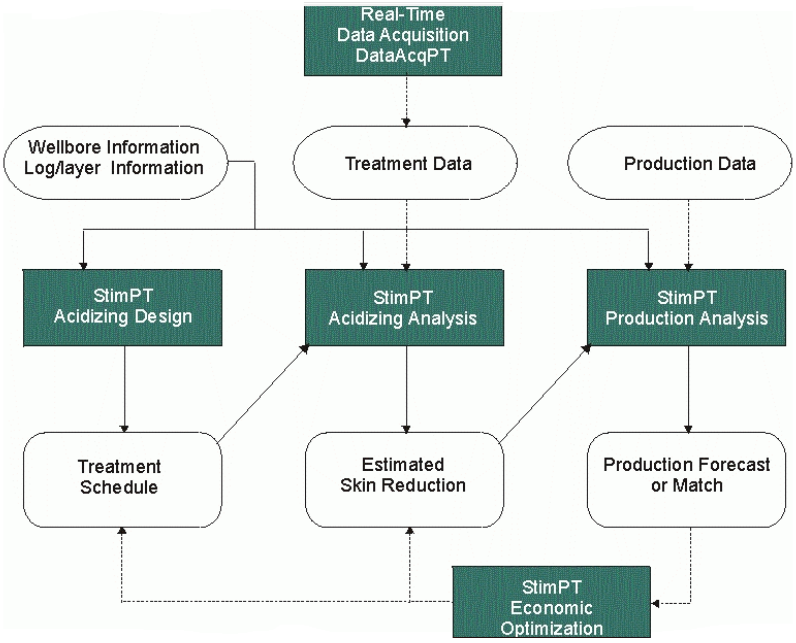


Fig 21- Methodology in StimPT[12]

1.15.1.3 Production Analysis

This mode gives the user the tools to analyze a well‘s past present and future production response from an economics point of view, both with and without a propped—fracture present This option runs ResrvoirPT which is the interface module connecting Stim.PT with different reservoir simulation models. Currently, the 2-D Fra.PS reservoir simulators is supplied with Stim.PT.[12]

1.15.1.4 Economic Optimization

In this mode the matrix acidizing simulator and the reservoir simulator are alternately run automatically in order to determine the economically optimalsize for the reservoir.[12]

1.15.2 Software Models

StimPT uses measured values of flow rate and fluid rheology parameters to calculate the pressure drop down a wellbore of variable deviation and diameter, and the growth of a matrix acidizing treatment. As output among other variables, the time histories of the matrix acidizing

treatment dimensions and the net pressure (fluid pressure below closure pressure) are calculated StimPT is comprised of a number of different models:[12]

- Wel1bore Model
- Friction Model
- Leak-off Model
- Heat Transfer Model
- Acid Model

1.15.2.1 Wellbore model

The wellbore module determines the pressure drop down the wellbore. It handles non-Newtonian fluids and corrects the density for the effects of nitrogen foam, carbon dioxide and acid pluses. The wellbore can be divided up into several sections, each with a different deviation from the vertical and with different flow configurations. Friction pressure is modeled with two flow rate regimes, laminar and turbulent. Behavior for these regimes is specified by entering three friction versus flow rate points: one in the laminar flow regime, one in turbulent flow regime, and one at the elbow or transition between the two regimes. Wellbore friction data is supplied for the fluids in the System Library. User defined fluids require the user to enter friction data All friction data can be edited to match observed (measured) friction data from simulations where suitable data was recorded The module accounts for friction variation from entrained acid by multiplying the base—fluid friction by a factor determined from a modified volume—l‘rac1ion—based Thomas equation. [12,13]

1.15.2.2 Friction Model

The friction model has required some modifications and corrections. In the first place, the

Clapp's equation has been re-written as

$$n/(f_c)^{1/2} = 0.45n\text{-}2.75+4.53\log[Re_c f_c^{(2-n)/2}] \quad \text{..... (10)}$$

from which (Clapp's fiic1ion factor, fc) the actual friction factor is still determined by

$$f/f_c = a_c - b_c \log Re_c, \; Re_c \equiv \rho V^{2-n} D / (K8^{n-1}) \quad \text{………………………..} (11)$$

but with the proviso that the choice of flow-rates (and associated frictional pressure drops) must be carefully chosen to span the range of ptac1ical rates (for example by using actual flow—rate changes on the job to get the data).[12,13]

1.15.2.3 Leak-off Model

The leakoff of matrix acidizing fluids from the matrix acidizing into the formation is one of the most important mechanisms in hydraulic matrix acidizing operations, because it affects the efficiency of the matrix acidizing treatment Fluid leakoff and filtration during matrix acidizing growth is a complicated process , but the fluid leakoff is normally simplified by the assumption that the flow of fluids from the matrix acidizing into the reservoir is one—dimensional and normal to the matrix acidizing face. With this simplification, the overall problem can be described by three fluid—loss coefficients to characterize the flow of fluids through the filter cake zone, through the invaded zone filled with the fluid filtrate, and through the non-invaded zone occupied by the compressed reservoir fluids. There are three leakoff model options in Slim.PT, all three of which are consistent with the assumptions and descriptions discussed above:[12,13]

- Lumped-Parameter Model
- Grid-Based Classical Model
- Grid-Based FLIC Model

1.15.2.4 Heat Transfer Model

Predicting accurate temperature profiles both in the wellbore and in the matrix acidizing is important for the design and analysis of well stimulation jobs. The problem can be solved either analytically or numerically. Since an analytical solution cannot handle variable fluid and rock properties and variable pumping rates, we have employed a unique numerical scheme that is not only accurate for calculating the temperature profiles, but that also runs fast enough for real-time analysis. Since temperature calculations in the wellbore are different from those in the matrix acidizing, two models are required to handle the two scenarios.

For temperature calculations in the wellbore, there is transfer of heat between different segments of pumped fluids along the pipe, between the wellbore fluids and the formation, and inside the formation In our wellbore temperature model, the heat transfer for pumped fluids along the pipe is handled as linear flow; the heat transfer between the wellbore fluids and the formation is handled through a heat transfer coefficient; and the heat transfer in the formation is handled as radial flow. The heat transfer coefficient is automatically estimated in the program, based on the correlation in the literature. The correlation for the wellbore heat transfer coefficient is dependent on fluid properties, flow regime, wellbore geometry, the thickness of pipe wall and cement sheath, and presence /absence of a deal fluid in the annulus, etc. Quite often, the estimated wellbore heat transfer coefficient is not very accurate because of complex wellbore conditions. To overcome the problem, you can calibrate the wellbore heat transfer coefficient if you have a temperature survey for any wells in the region.

Similarly, for temperature calculations in the matrix acidizing, there is transfer of heat between different segments of pumped fluids in the matrix acidizing, between the matrix acidizing fluids and the formation, and inside the formation In our matrix acidizing temperature model, the heat transfer for pumped fluids along the matrix acidizing is handled as linear flow; the heat transfer between the matrix acidizing fluids and the formation is handled through a heat transfer coefficient; and the heat transfer in the formation is also handled as linear flow. The correlation for the matrix acidizing heat transfer coefficient is dependent on fluid properties and flow regime. You can also calibrate the matrix acidizing heat transfer coefficient to match your flow—back temperature data.

Partial differential equations for governing heat transfer processes along the wellbore and in the matrix acidizing were constructed mathematically and solved numerically. The numerical solution for the wellbore model was obtained by coupling the 1-D linear heat transfer along the wellbore with the 1-D radial heat transfer in the formation surrounding the well. The wellbore heat transfer model was verified by analytical solutions and with measured bottomhole temperature data Likewise, the matrix acidizing temperature model was solved numerically by assuming 1-D linear heat transfer inside the matrix acidizing The matrix acidizing temperature model was verified by analytical solutions and calibrated by measured bottomhole temperature data flowback immediately after the pumping of a matrix acidizing treatment.

The figure below shows temperature data from a matrix acidizing treatment with flowback data StimPT‘s heat transfer model compares fairly well with measured temperature data.

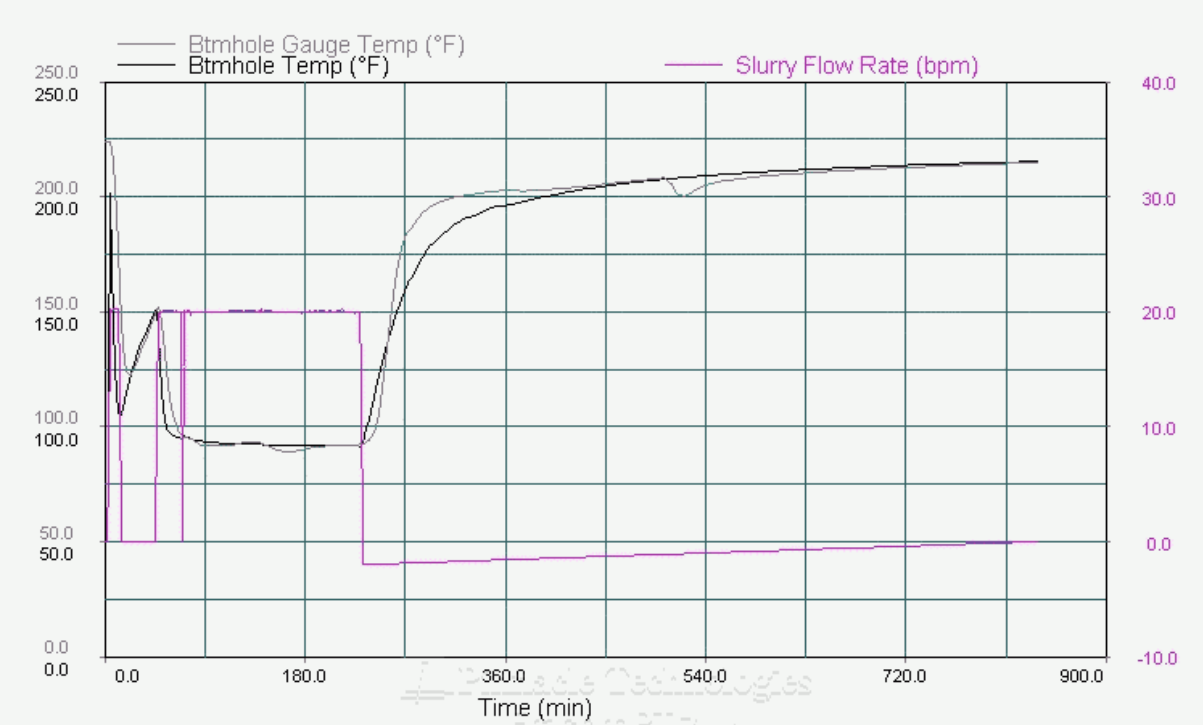


Fig 22- Comparison of measured and modeled bottomhole temperature

Neither the simulated nor measured temperature after 10 hours of flow back is close to the reservoir static temperature of 265F. The behavior of heat conduction in the reservoir is similar to the transient pressure change. For a typical reservoir rock the thermal diffusivity is about 0.7 - 0.9 ft^2/day. However, for a typical gas reservoir with a permeability of 1 mD, porosity of 10%, Viscosity of 0.03 cp, and compressibility of 3.0E-4 psi^{-1} the hydraulic diffusivity is 0.7E3 ft^2/day. To make the gas reservoir flow diffusivity to the same order of the thermal diffusivity, say 0.7 ft^2/day, we need to have a rock permeability of 0.1 mD. This analysis means that thermal flow in the reservoir is similar to the fluid flow in a tight gas reservoir. For a tight gas reservoir, after a short period of production or pressure draw down, it takes many days (or even months) for the pressure near/around the wellbore to be built up to its original reservoir pressure. Similarly, it will take a long time for the bottomhole temperature to reach the original reservoir temperature.

This feature can accurately predict the wellbore temperature profile during pumping and shut—in stages, and allows more accurate breaker scheduling, as the temperature profile inside the matrix acidizing is accurately calculated at any position at any given point in time.[12,14,15]

1.15.2.5 Acid Model

StimPT's acidizing model takes into account the inherent differences between acidizing in carbonates and limestones. In carbonates, the purpose of acidizing is to dissolve the matrix forming new channels (wormholes) that bypass the damaged areas and lead to the wellbore. In contrast sandstone acidizing emphasizes dissolving particles that clog existing pore channels rather than creating new ones. Wormholing is only one of several etching patterns that can be obtained when acidizing in carbonates. However, because wormholes lead to the best skin reduction, fluid reactivity and flow rate are normally optimized for their creation StimPT facilitates this optimization process. Highly reactive fluids are needed to create wormholes; however, the kinetics are dominated by Mass-transfer limitations he flow rate is too low, all the rock at the face starts dissolving before the fluid has a chance to enter the formation. This process is referred to as compact dissolution. If the flow rate is too fast, the fluid breaks through the damaged zone before any wormholes have a chance to form, resulting in a more homogeneous etching pattern.

The acidizing module characterizes the wormholing process by fractals, which remain the same Regardless of scale. In physical reality, this self-similarity is true only in a specific domain defined by limits called cutoffs. However, the concept opens the way for quantification of the process. Modeling the hydraulic properties of wormholes in the near-wellbore region is actually similar to modeling' skin. With skin, an equivalent wellbore radius is defined that is associated with the extra pressure drop (positive or negative) resulting from the damaged region. For wormholes, an equivalent wellbore radius is defined such that there is no pressure drop between it and the formation face. Beyond the equivalent radius, Darcy's law applies.

Sandstone reservoirs, the acid typically moves in a front spreading out around the wellbore. The difference in behavior is due largely to the act that the kinetics of dissolution for sandstones is surface-reaction limited. The process is much more stable than found in carbonates. A typical treatment in sandstone uses a mud acid mixture of hydrochloric (HCl) acid and hydrofluoric (HF) acid to re-open and enlarge pore channels clogged with clays and siliceous fines. The HCl acid

dissolves any carbonates within the matrix and prevents the clays from extracting protons from the HF acid. The HP acid dissolves slow- and fast-reacting silicates and carbonates.

Treatment effectiveness often hinges on being able to determine the optimum acid treatment volumes and concentrations. Secondary reactions from spent acid can result in the precipitation of amorphous silica, there by contributing to the skin rather than reducing it. In contrast, acid that is too strong can weaken and compromise the rock matrix at the formation face. By modeling the various primary and secondary reactions in the reservoir, ERROIC: Variable (Sinmlator-Matrix-Acidizing-Stinmlation) is undefined provides a systematic approach to determining the optimum treatment volumes and concentrations.[12]

Chapter 6: Case Study and Results

In this project one of the south west Iranian wells has been analyzed before and after acidizing by evaluation of its welltests. Beside that evaluation, its acidizing treatment has been simulated by technical software that explained previously in past chapter. At last it will be compared to welltest analysis to show how the models are working and how much they work correctly.

First of all for starting the simulation the software request several well's parameter as input .These parameters are listed in fig. 23.

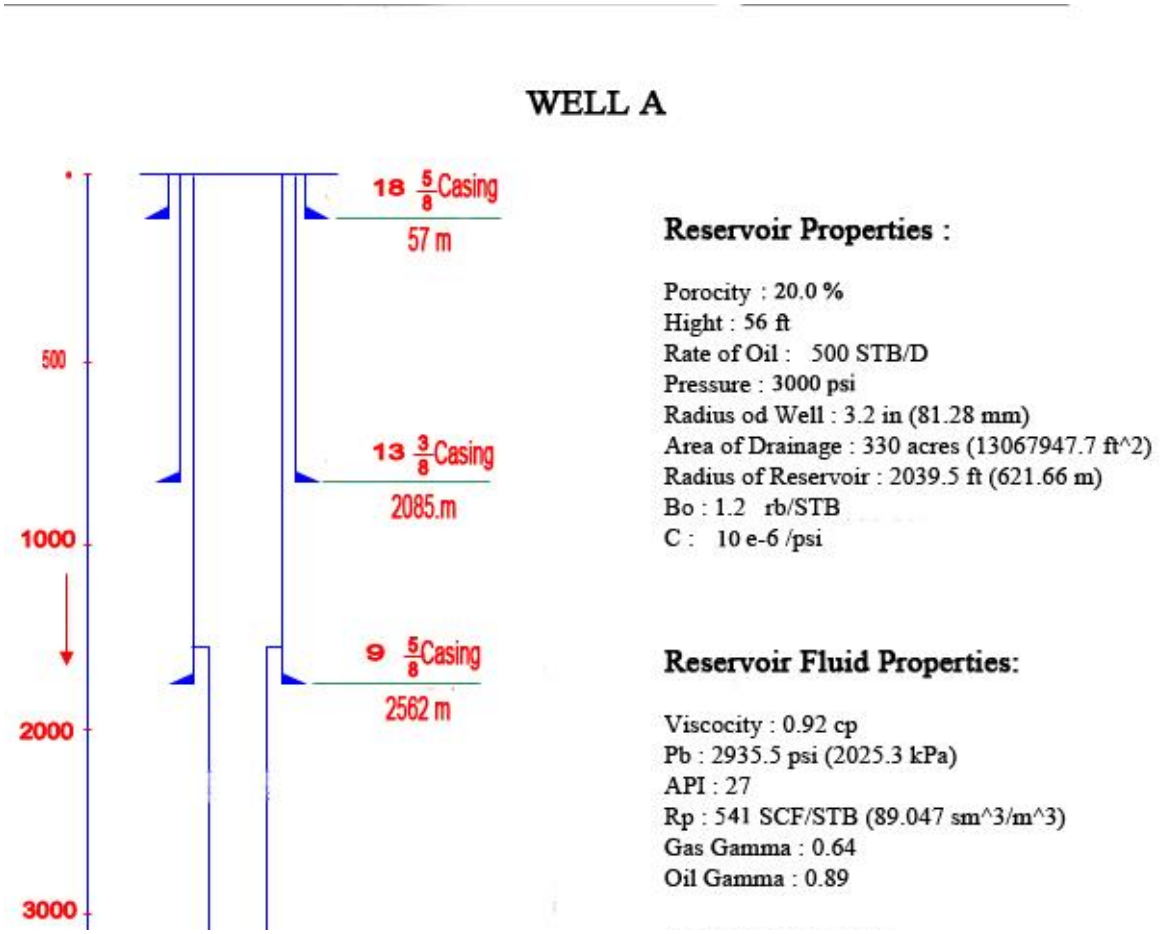


Fig 23- Case study well parameters

So the parameters must enter correctly in to the software windows like the fig. 24 and 25. After that the software is ready to run and simulate the acidizing treatment and it will prepare the result in multistage table. That table has shown in Fig 26. As it is obvious each row is represents a stage

of the acidizing treatment and it is showing that how much it reduce wellbore skin and help the production of well. These kind of simulation and results that can obtain from the software is depend on user skill and working background. For investigating the results of the software they will be compared to welltest analysis. Usually in field for evaluation the effect of acidizing in reservoir the production engineer preform two welltests before and after the acidizing, here in fig. 27 and 28 it has shown the results of the welltest well A after and before acidizing and they can be compared with simulated data from StimCADE.

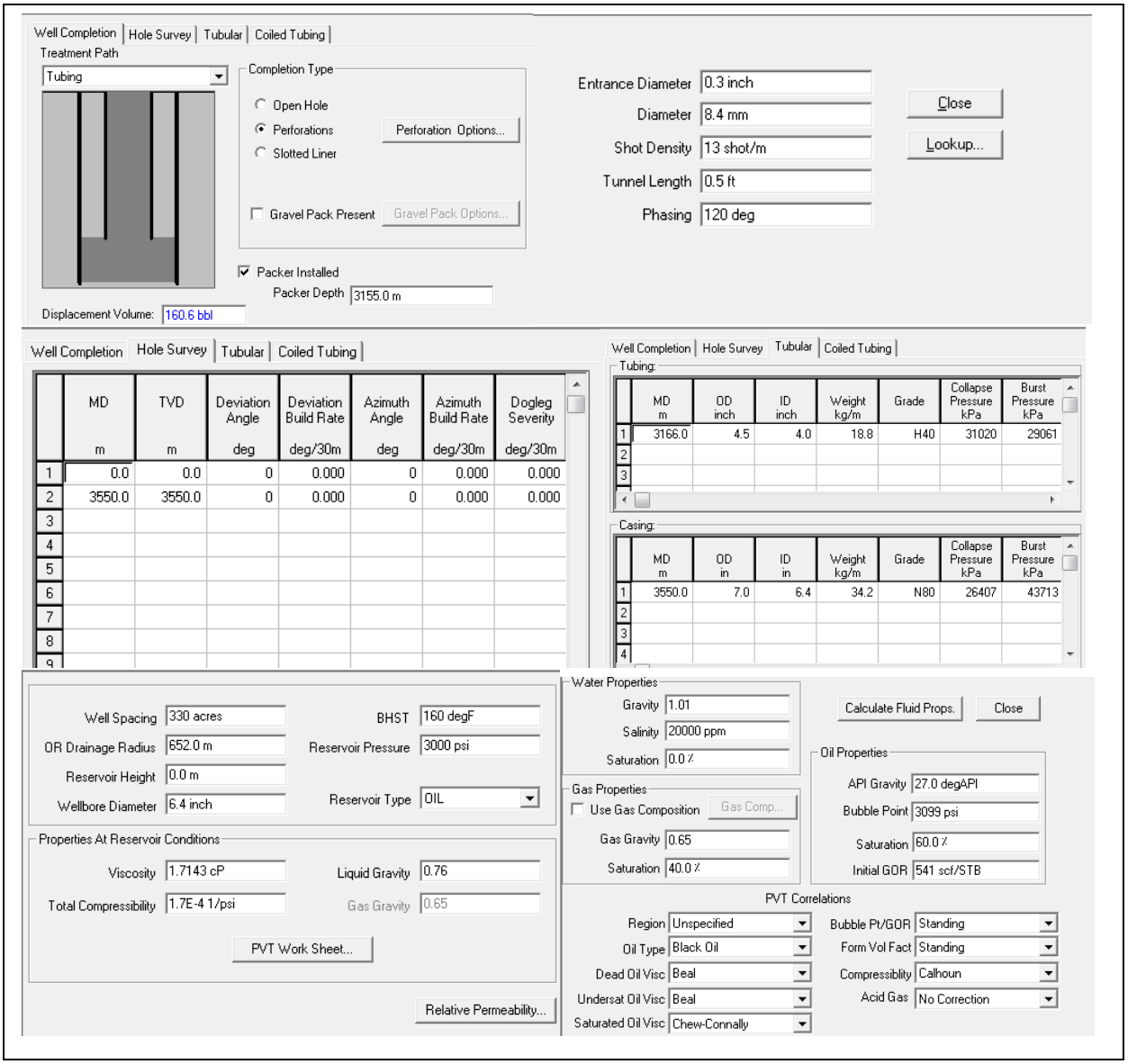


Fig 24- Input Windows of StimCADE software (General Information)

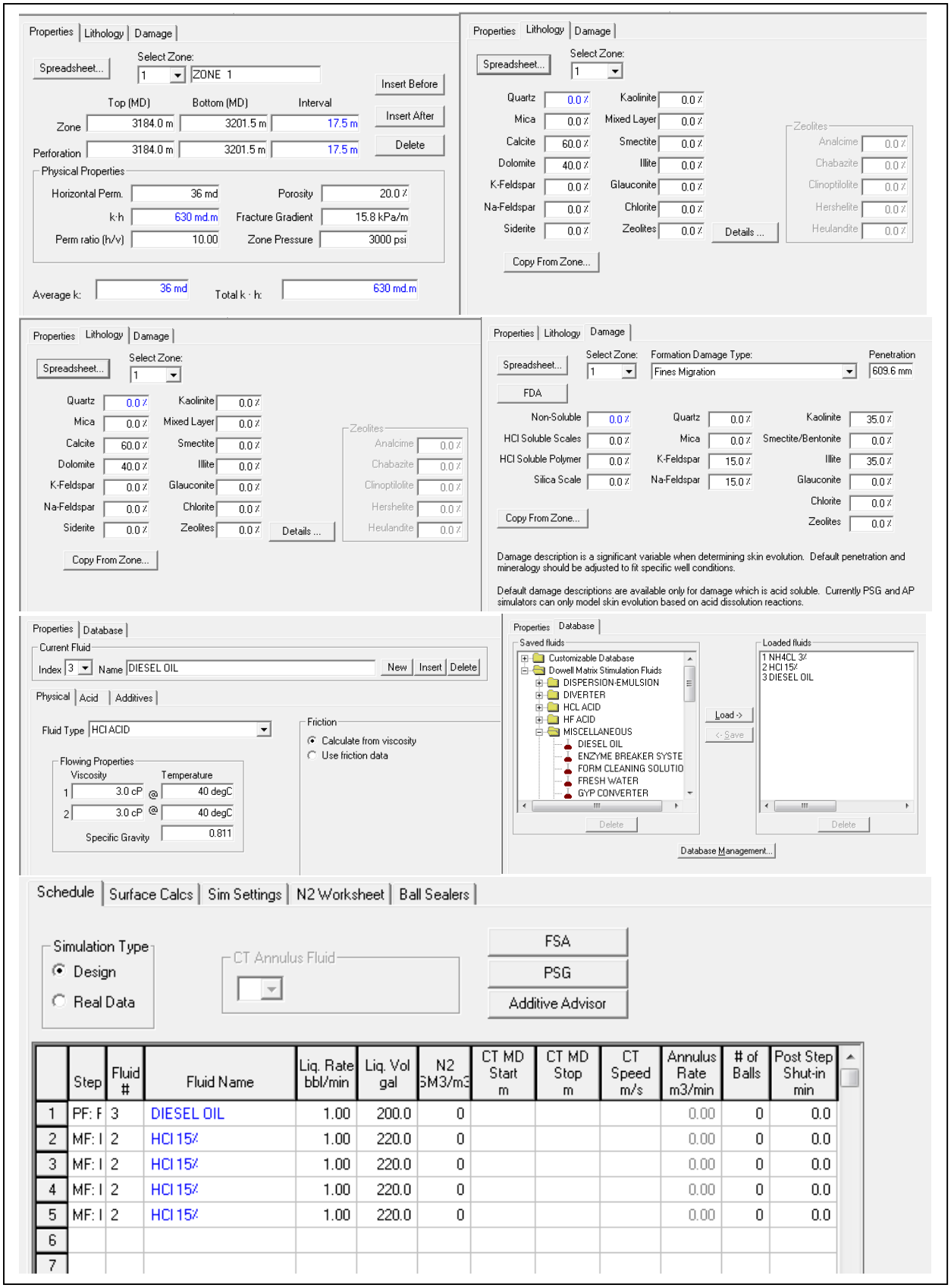
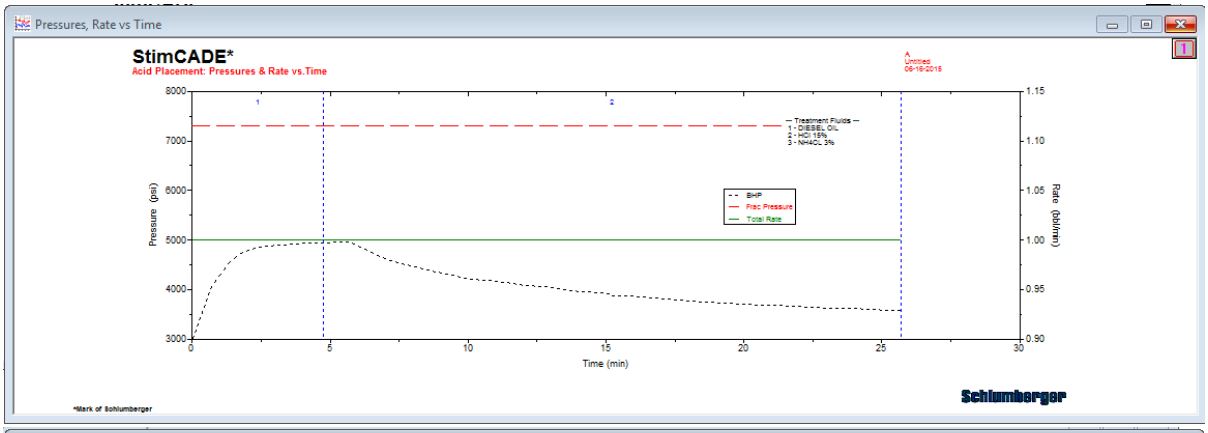


Fig 25- Input Windows of StimCADE software (Acidizing Treatment Information)

It is so clear that the simulated results are very close to real condition data and can be concluded that they can be reliable.



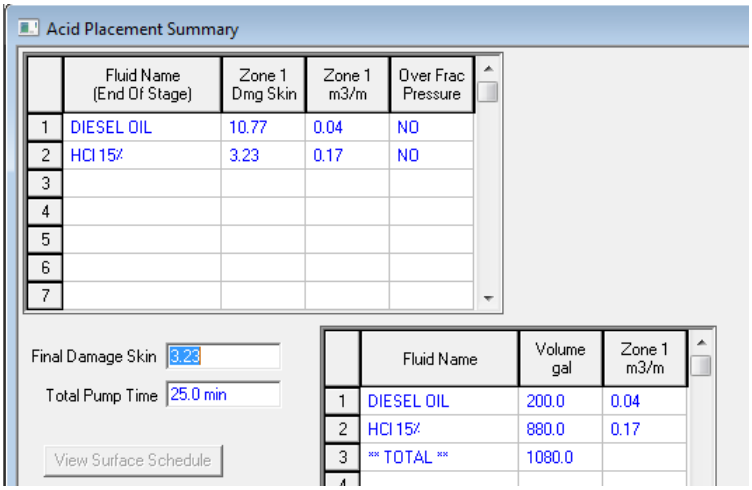


Fig 26- Result data from StimCADE software

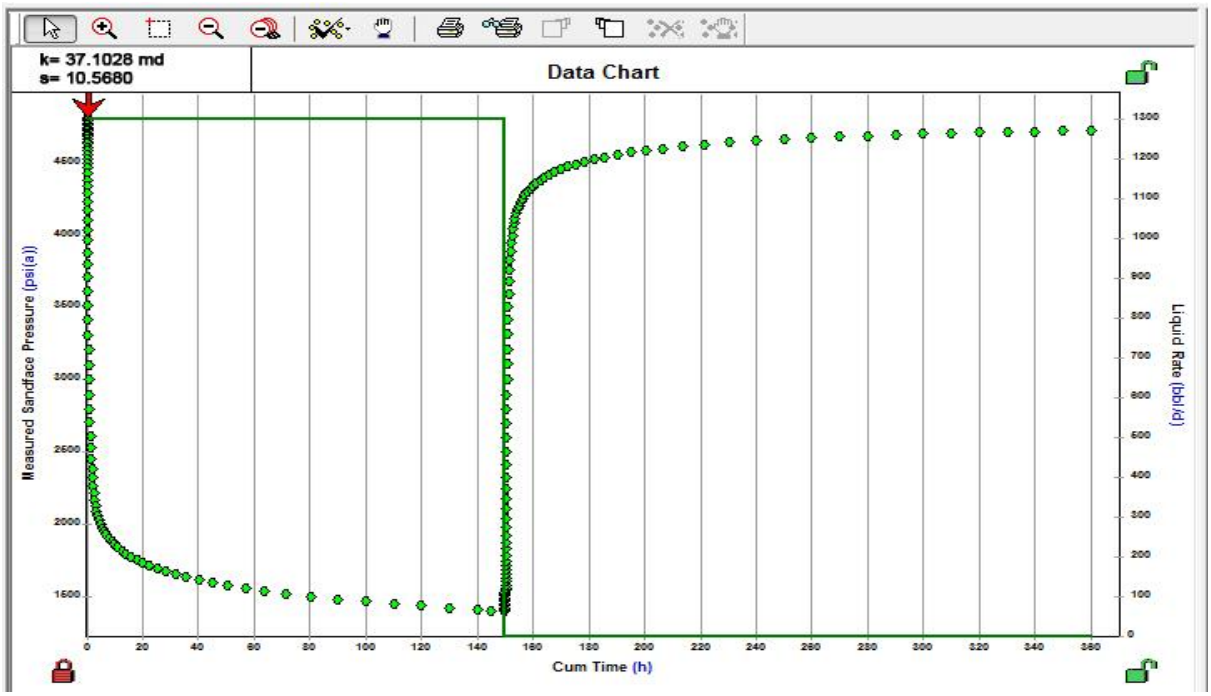


Fig 27- Welltest analysis before acidizing with FEKETE F.A.S.T software

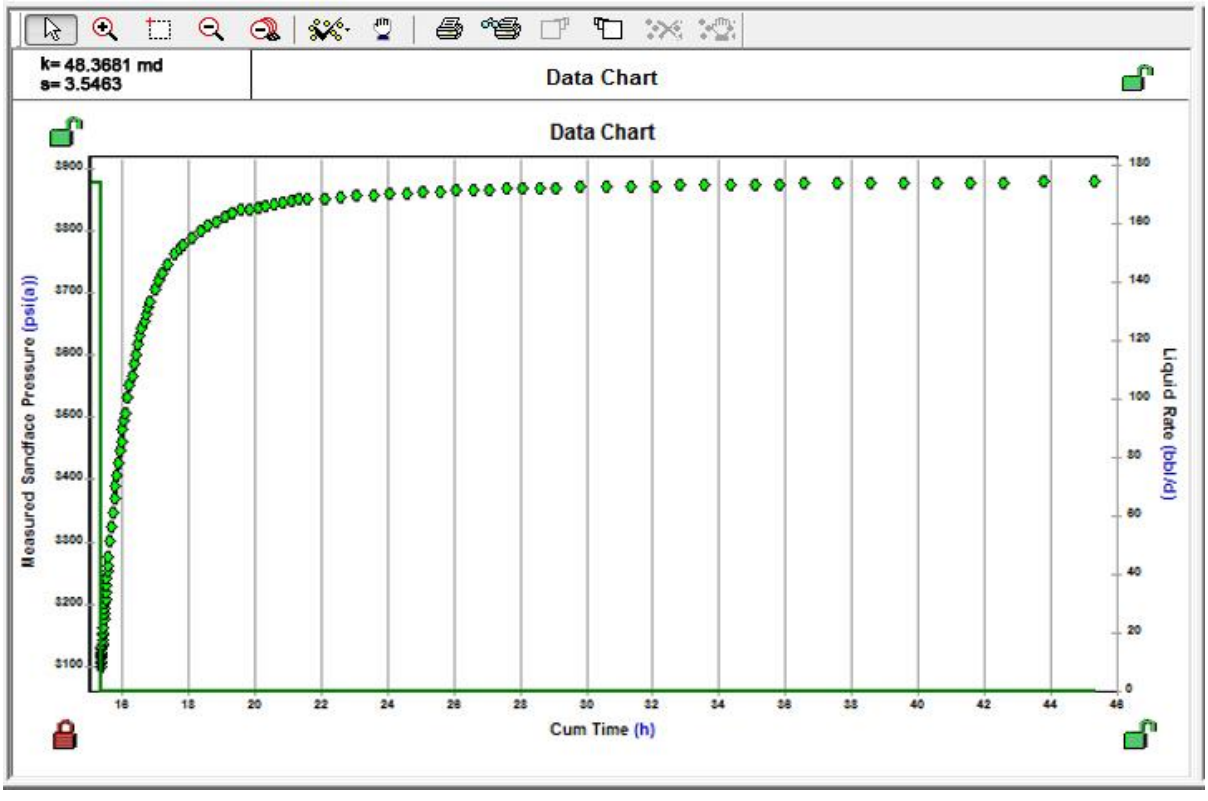


Fig 28- Welltest analysis after acidizing with FEKETE F.A.S.T software

Conclusions

1. Matrix acidizing can be very beneficial to many damaged oil, gas, and water wells, but not all matrix treatments are successful even when the well is severely damaged. A complete and accurate well and formation analysis, treatment design, well preparation, job supervision, and followup evaluation all are required to achieve maximum benefit from matrix acidizing.
2. Results obtained under a given type of geometry cannot be directly applied to another without accounting for the change in fractal dimension.
3. For a linear ID geometry, the conductivity properties of the pattern are entirely described by Eq. 5 (except for the dependence on the sample cross section).
4. For a radial geometry, the skin decrease can be predicted from Eq.7.
5. Eqs. 5 and 7 are valid provided that the Peclet number is higher than unity; i.e., the dissolution produces wormholes and not a compact pattern. Gravity effects have to be considered when this critical value is calculated.
6. StimCADE is a comprehensive design and evaluation package which brings a structured engineering approach to the problem of matrix stimulation. Currently, well treatment design and evaluation is highly dependent on local practice guidelines, individual expertise, or both. It is regarded as more art form than science. StimCADE emphasizes the scientific aspects of the process, enhancing the probability of attaining improved well performance.
7. The StimCADE service addresses all aspects of the matrix stimulation treatment from candidate selection through post-treatment evaluation. lt provides a detailed engineered pumping schedule and develops measurable success factors, based on the operators specific objectives. During job execution, the StimCADE package will provide the means to monitor rates/pressures and skin.
8. Post—treatment evaluation focuses on the operators' objectives versus actual well performance and will improve service company quality in all phases of the DESIGN-EXECUTlON-EVALUATION process.
9. It is so clear that the simulated results are very close to real condition data and can be concluded that they can be reliable.

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