CARBONATE ACIDIZING – DESIGN FOR SUCCESS

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ABSTRACT

Oil and gas production from conventional and unconventional formations, with both always requiring some form of stimulation. Limestone and dolomite are considered conventional formations which are stimulated with various treatments, either above fracturing pressure or below. Treatments above fracturing pressure are hydraulically created cracks that use either proppant or acid to maintain flow paths after closure. Matrix treatments performed below formation fracturing pressure use acids to create wormholes that penetrate into the reservoir bypassing any near wellbore damage.

This paper provides an overview of the process that should be implemented in the design of an acid stimulation treatment to provide the best opportunity of successful production improvement. Specifically being addressed are the criteria that defines the need for an acid treatment and whether that should be a matrix or fracture treatment. In addition, the choice of an acid fracture treatment over a propped treatment is discussed. The specifics of how staging and diversion can be used to obtain better zonal coverage, how to overcome temperature limitations and other operational concerns. are also addressed.

WHAT IS INVOLVED IN ACIDIZING CARBONATE FORMATIONS?

Acid is often chosen for stimulation of carbonates due to the large amount of reservoir rock that can be dissolved per gallon of acid, **Table 1**.[1]

The equation governing this dissolution is basically the same for all acids,

$$\boldsymbol{Acid + Carbonate \rightarrow CO_2 \uparrow (Gas) + H_2O + \ Salt}$$

This equation represents strong acids like Hydrochloric Acid reacting with a carbonate rock. Weaker acids, like organic acids (Acetic, Formic), can be represented by a similar reaction except the reaction is reversible. The process works as long as all reaction products are soluble, thus Hydrofluoric Acid is not used on carbonates because Calcium Fluoride and Magnesium Fluoride are insoluble. This dissolution of rock allows an acid to bypass near wellbore damage by creating "wormholes" around the material blocking production. It also allows the creation of channels when fracture treatments are applied which can provide deep conductive flow paths from a reservoir.

WHEN SHOULD CARBONATE RESERVOIRS BE ACIDIZED?

Damaged Production

Carbonate reservoirs are subject to treatment with acid either when production has been reduced as a result of some damage mechanism or when production is at an uneconomical rate due to low permeability of the rock. When production declines to a rate lower than theoretically expected based on reservoir analysis the reason is typically some material blocking the conductive paths, formation damage.

WHAT ARE THE SOURCES OF DAMAGED PRODUCTION?

Due to different operations associated with drilling a well to reach a producing horizon formation damage may occur. In addition, just producting the well may cause formation damage. The industry goal is to minimize the effects that during all of these operations. However, it is impossible to avoid some damage. Typical types of formation damage are listed in **Table 2**.

Table 3 lists the associated damages that can result from well operations initially, after it has been producing or after injection of water.

If the damage is shallow to moderate in depth of penetration, a matrix acid treatment should be able to remove or bypass this damage and restore production. Since it is difficult to pin down exactly what the damage is in a well, examination ofthe history, production and produced fluid compositions can greatly help in the treatment decision.

Low Permeability

A well with deep formation damage or low permeability requires a fracturing treatment to create economic production. The fracture treatment can either use proppant or acid to provide conductive paths deep into the reservoir. **Figure 1** illustrates the goal of an acid fracture treatment.,On the left is the fracture after closure, if the formation can be differentially etched and is strong enough to hold open the created channels. Depending on the technique it is possible to create more fracture than is acidized with channels, as seen on the right.

MATRIX ACID TREATMENTS

Treatment Design

When evaluating whether to perform a matrix acid treatment, it must be determined that there is formation damage that can be removed or bypassed by acid. **Figure 2** illustrates a decision tree which emphasizes several reasons production may be poor from a well.

Once a damage mechanism is understood to be moderate to shallow in penetration of the reservoir, then the process of designing the treatment may begin. The process starts with determining the fluid and additive choices for the removal or bypass of the determined damage. Next, understanding the undamaged reservoir, the mineralogy and fluids, is critical to making a selection of the proper fluid and additives from the list of choices. Lastly, the design process takes into account any reactions with the surface and sub-surface equipment while pumping the treatment. The last two steps are to prevent any further damage to the reservoir, eyond the damage being addressed. All treating fluids removing or bypassing the damage will come in contact with the undamaged formation.

Figure 3 illustrates the process of working through the problem and determining the solution(3 possible sources listed for illustration).
Knowing that formation damage exists, examination of possible sources can improve confidence in the suspected damage. . Where the damage is located is the next item of importance to the treatment design,s it in the wellbore, several inches into the reservoir or several feet. A matrix treatment can get past shallow to moderate depth damage or a hydraulic fracture treatment to address deep penetration. Lastly, comparethe options of fluids and additives that can successfully treat the problem.

Over the yearsresearch has been conducted to understand matrix treatments on carbonates and how to improve the creation of the wormholes. **Figure 4**[2] illustratesthe effects of rate on wormhole creation using low concentration of hydrochloric acid. As the diagram shows there is an optimum wormhole from the wellbore to the undamaged reservoir.

The optimum wormhole varies with acid type, acid strength, injection rate, rock composition, fluid leak-off control and temperature. Core flow tests in a laboratory can identify the values essential in determining these parameters.

Unless the stimulation history is considered in the design process, it is very likely the -designed fluids and additives will not provide the results desired. If a well has been acidized before then the amount of surface area a subsequent acid treatment will come in contact with has increased. As illustrated in **Figure 5,** if a treatment is not properly designed an acid treatment may not penetrate as far as prior acid treatments.

In addition to, an optimum injection rate, it is essential that the rate and surface treating pressure (STP) avoid fracturing the formation. Staying below fracturing conditions ensures that treating fluids have a higher probability of reaching the entire radial area around the wellbore. Equations 1 and 2 are used to determine the maximum injection rate for a vertical well and a horizontal well, respectively. Equation 3, is used to calculate the maximum STP to avoid fracturing. These values are normally higher than the determined optimum injection rate for the treatment.

$$Eqn(1) \qquad q_{Max} = \frac{(4.917 \times 10^{-6})kh\left((Frac\ Gradient \times Depth) - P_e - P_{Safety\ Factor}\right)}{\mu\left[ln\left({}^{r_e}/_{r'_w}\right) - 0.75\right]}$$

$$Eqn(2) \qquad q_{Max} = \frac{(4.917 \times 10^{-6})\sqrt{k_H k_V}L\left((Frac\ Gradient \times TVDepth) - P_e - P_{Safety\ Factor}\right)}{\mu F}$$

$$F = {}^{1}/_{2}\, ln\left[\frac{8hI_{ani}}{\pi r_w(1 + I_{ani})} \times cot\left(\frac{\pi z_w}{2h}\right)\right] + {}^{1}/_{2}\left[s - \frac{(h - z_w)I_{ani}}{L}\right]$$

$$Eqn(3) \quad STP_{Max} = BHFP + Perf\ Friction + Tubing\ Friction - Hydrostatic\ Pressure - Safety\ Factor$$

It should be noted that the rate is dependent on the damage and the calculated maximum injection rate will increase as damage is removed.

Fluids and Additives

The choice of base fluids is a short list as seen in **Table 4**, typically used acids and solvents. Many of these fluids can be used to deal with several damage mechanisms as seen in **Table 5.**

Table 5 lists some basic fluid systems versus damage mechanism . The different fluids options allows the design engineer flexibility to avoidfurther damage of the reservoir but also allows for utilizing logistic available.

The volume of treating fluid is a function of penetration and increased porosity desired to achieve stimulation. A simplistic approach to calculate the acid volume starts with the overall rock volume to be treated over a desired penetration and determine how much rock removed would give a 5 to 15% porosity increase.[3] Dividing this quantity bythe dissolving power of the acid yields the acid volume range. More accurate designs are generated using numerical simulators that have been developed. **Table 6** illustrates this simple calculation.

Table 7 lists some generic additive choices used in acid treatments. While the base fluid is the primary means of clean-up or bypass damage, the additive packages to support this effort and provide stability when the treatment fluid enters the undamaged reservoir.

All fluids must be compatible with reservoir fluids to ensure stable emulsions are not created by mixing treatment fluids and reservoir fluids. In addition, to avoiding stable emulsions, it is also essential to avoid sludging.. Sludging is the result of acidic fluids causing flocculation ofasphaltene particles in the reservoir oil. **Figure 6** is an example of an asphaltene particle chemical structure and **Figure 7** illustrates the result when a sample of San Andres oil and 15% Hydrochloric Acid (without additives) are mixed.

The test should be performed with live acid and spent acid with and without iron being added to them. This will show the severity of the problem and help define the type and quantity of additives to be used in the acid.

These tests are used to select the proper non-emulsifiers and iron control additives for the fluids. Another consideration is whether the reaction products in the spent acid will increase the saturation in the reservoir water where re-precipitation will occur. For example, a reservoir with a high chloride concentration water treated with Hydrochloric Acid causes the chloride concentration to exceed the saturation limit and precipitates salt.

Any potential reactions of the treating fluid with the undamaged mineralogy needs to be considered, such as insoluble fines, clays, iron compounds, etc. A dolomitic formation that is 100% soluble in acid may conatain calcite which reacts first with the acid. If there is not sufficient acid left to dissolve the dolomite there can be soluble particles in spent acid. These particles can act as migratory fines plugging up the conductive paths created by the acid. So whenfines might be generated a suspending agent or viscosifier may be needed in treating fluid recovery and to carry fines out of the well.

As mentioned above, a fluid selected to remove or bypass damage must be evaluated for reactivitywith the metals to be contacted (pumps, tubing and any tools) during the treatment. The reasons are corrosion and the reaction with iron scales (Corrosion Products from O_2, H_2S and/or CO_2) in the wellbore (Fe_2O_3, FeS and/or $FeCO_3$) which puts iron in solution. This dissolved iron could precipitate with increasing pHin the undamaged formation.

In addition, to the conditions already addressed, the selection of viscosifier or friction reducer may be required to achieve the necessary pump rate, leak-off control and/or suspension of solids.

Rate, Pressure and Staging

Acid penetration into a formation is controlled by the reactions already described. Fluid loss and optimum injection rate are only one part of a successful acid stimulation treatment. The other is whether the interval is being treated completely. Placement of the treating fluid involves staging to move the fluid around in the interval being treated. The stages are volumes of the treating fluid separated by some method of diverting the fluid to a different part of the interval. Diversion can be accomplished in several ways, one example being the use of packers and plugs to isolate intervals to treat. Another common method is to utilize coiled tubing. Additionaly, there are materials that can be added to the acid or another fluid to facilitate the fluid movement in the wellbore. Typical diverter materials used in the industry are listed in **Table 8**. Diverter choice depends on efficiency of the material, pump rate, fluid being pumped and well configuration. When pumping a staged treatment, it is essential to maintain a constant rate while the diversion stage reaches the interval so that the STP changes reflect the diverter effect.

Figures 8, 9 and 10 are rate and pressure charts exhibited on some typical acid treatments using different diversion methods. **Figure 8** is a horizontal well using two methods of diversion, first mechanical isolation using packers and sliding sleeves, and also a viscoelastic acid system. It is clearly evident from the increasing STP that each stage of diverter was effective. **Figure 9** illustrates ball sealers added continuously throughout the acid treatment with the STP steadily increasing from 7250 psi to 7960 psi. **Figure 10** is the acid treatment rate and pressure chart using Rock Salt diversion material.

Treatment Execution

Knowledge of the well and the problem are critical to success and the treatment design to accomplish this success is also extremely important but it must be executed correctly. Execution involves performance in a safe manner, observing good quality control (QC), monitoring and recording everthing during the treatment. Making sure all personnel are wearing their Personal Protection Equipment (PPE), know the meeting site in the event of an emergency, where the nearest hospital is located and who is the designated driverto the hospital. In addition, any location where acid is pumped should have a safety shower and eye wash station.

The pumping procedure should be reviewed and fully understood by all participants. This includes where fluids are located and what order they should be pumped. Also, everyone should be aware of alternative options in the event rates and pressures are not as design.

QC

All fluids should be checked to ensure being mixed correctly. This includes checking for acid strengths (titrated to ±1%), correct additive concentrations and volumes. Individuals responsible for opening and closing valves are aware of when and how much to be pumped. If possible, perform bottle shake tests verifying non-emulsion capabilities of fluids. If diverters are to be used ensure correct materials in sufficient volume to handle any alterations in the procedure are located properly.

Monitoring

The rate and pressures observed during the treatment should be electronically recordedalong with, the rates all chemicals are added “on the fly”. The treatment report should be complete with all pertinent well information, a complete set of notes describing the treatment. Treatment events described include: if a pump went down, chemical variations; changes in concentration of diverter, etc. These records are important to understand the subsequent well production relation to different treatments performed on wells in the area. They also are of great assistance in the design of subsequent jobs on the same well.

Treatment Evaluation

There are many ways to evaluate a treatment, this includes treatment fluid recovery, emulsions observed, composition of recovered fluids help determine if the correct fluids were pumped for the damage, and did the treatment pressures and rates reflect the design and the anticipated values. The primary evaluation is based of course on production performance, both initially and long term.

EXAMPLE MATRIX TREATMENT

A vertical well with 5-1/2" 17# J-55 casing set at 7300' was completed 6 months ago and is now producing 90 BOPD, 30 MCFD and 15 BWPD. Offsets are producing at 200 BOPD, 70 MCFD and 25 BWPD. The well initially made 109 BOPD, 70 MCFD and 5 BWPD. After 4 months the well was acidized with 1500 gallons of 15% HCl at 5 BPM and an average STP of 2000 psi. There was no staging and the treatment tubing string was not pickled. The formation is 25% Calcite, 55% Dolomite, 15% Anhydrite and 5% Chert. Immediately after this treatment it was making 134 BOPD, 50 MCFD and 15 BWPD. There are three sets of perforations at 7000' to 7020', 7075' to 7100' and 7130' to 7145', each with 2 shots per foot. The well is supposed to drain a 40 acre area. Permeability averages 8 mD and porosity is an average 12%. A water analysis indicates calcium carbonate scale is probable. So the low production is due to scale, probable incomplete treatment with the first acid treatment and possible damage from the acid job.

Analysis of the production initially indicated that the skin factor was 8 and had been improved to 5 after the acid treatment, has gone up to 10. Based on this information and that above an initial maximum injection rate for the treatment should not exceed 1 BPM and approach 3 BPM if all the damage was cleaned up. This is based on a fracture gradient of 0.75psi per foot. Looking at the calculated maximum STP to avoid fracturing the zones, it was determined the well previously had been acidized at fracturing rate and pressure

Using a simple calculation from before an acid treatment using 7500 gallons of 15% HCl using a viscoelastic acid diversion should clean up scale, treat the entire interval while removing 10% of the reservoir rock.

FRACTURE ACIDIZING TREATMENTS

Why Acid over Proppant?

Hydraulic Fracture treatments are used to achieve either the bypass of deep damage to a formation or for the purposes of stimulation of a low permeability reservoir. These treatments employ rate, pressure and fluids to create a crack in the rock which is then filled with solids of sufficient strength to hold open the crack once pressure is released. These solids are called proppants. In the case of carbonate formations there is another option to the proppants being placed in the crack, this is to use an acid system which etches the rock face of the crack leaving a rough surface. The high spots of this rough surface will hold open the channels created by the acid to provide the conductive path. The decision to use acid instead of proppant is based on several factors. These factors include the hardness of the formation, solubility, closure strength of the formation and temperature. **Figure 11** is a decision tree to evaluate whether a formation should be propped fracture treated or acid fracture treated.
The numbered boxes at the bottom of the tree in Figure 11 refer to the list below:

1. Formation slow reacting with some leak-off problems due to high compressibility
2. Formation more reactive and creates additional leak-off problems
3. Formation highly reactive and increased leak-off issues
4. Formation slow reacting with leak-off not as big an issue due to low compressibility and high reservoir fluid viscosity
5. Formation more reactive leak-off a bigger issue
6. Extremely reactive formation with extreme leak-off issues

These are additional conditions that will need to be addressed in order to make an acid fracture treatment successful.

Treatment Design

Once it is known that an acid fracture treatment is the treatment of choice there are several components that have to be evlautated. These components involve the fluids to be used, how fast is the treatment to be injected into the formation, staging to cover the interval and anything special that needs to be done with regard to technique.

Fluids and Additives

The acids to be used will depend on the spending rate in to the formation, the leakoff expected, the required fracture geometry and the required conductivity to provide economic production. There are several fluid composistions to choose from to control reactivity depending on the mineralogy and the temperature, **Table 9**.

Additional additives in the acid system chosen for an acid fracture treatment would be the same as those described in the previous section on **Matrix Treatments.** The only additive that might be used additionally would be a friction reducer to facilitate higher injection rates.

Rate, Pressure and Staging

The most characteristic difference between fracturing with acid and with proppant is that the width generated is not as critical to the success of the treatment because the width does not need to be of a size to accept a proppant. Injection rate of hydrochloric acid affects the penetration:

- Neat HCl penetrates a dolomite farther than a limestone with increased rate by 67% to 38% at 200°F.
  - As the temperature increases to 275°F the difference in penetration approaches zero.
- Differences in penetration can be controlled with the acid composition.

Closed fracture acidizing (CFA) is a technique where following an acid fracturing treatment the fracture is allowed to close and a small stage of acid is pumped into the closed fracture at matrix injection pressure. Rate is typically used to control fracture height, effectiveness of diversion techniques and fluid loss.

Tables 10 through 12 give partial guidelines on staging and fluid volumes based on size of tubing and casing as well as interval thickness to be treated. Further tables for additional tubular sizes, rates and interval thicknesses can be developed based on an area of interest.

Table 10 gives a guideline on the stage volumes to be pumped. The volumes are increasing through the stages to ensure that zonal coverage takes place given the fact that diversion techniques lack the ability to be 100% efficient**.** **Table 11** is a guide to the number of stages if treatment is being pumped down 5-1/2" casing compared to the zone thickness. Likewise **Table 12** is a guide similar to **Table 11** but for treatments down 2-7/8" tubing.
Methods of diversion are:

- Mechanical
  - Isolation
- Solids
  - Bridging Agents
- Pump Rate
  - Limited Entry
- Viscosity
  - Polymers
  - Foam
  - Viscoelastic Surfactant Systems

These methods each have their own optimum usage conditions and even when in the most favorable situation a degree of efficiency below 100%. The solids that are typicaly used for diversion are ball sealers, rock salt, benzoic acid flakes, oil soluble resins, naphthalene flakes, polymer pills, wax beads, Gilsonite and resin beads and their goal is to bridge in a perforation or the created fracture. Viscosity controlled zonal coverage is accomplished the diverter fluid having a higher degree of drag and viscosity differential over the main acid treating fluid. These systems generally consist of foams, polymers or viscoelastic surfactant systems.

Treatment Execution

FIGURE 12 IS A REPRESENTATIVE OF HOW THE RATES AND PRESSURES MIGHT VARY ON A FRACTURE ACIDIZING TREATMENT. ALL THE ITEMS DISCUSSED IN THE SECTION UNDER

MATRIX TREATMENTS APPLY FOR FRACTURE ACIDIZING TREATMENTS, INCLUDING SAFETY, QC AND MONITORING.

Treatment Evaluation

Evaluation of the rates and pressures is a good way to identify if the treatment accomplished what was needed. Matching these to an acid fracturing model will help to understand the geometry of the created fracture. Evaluation of production and pressures after the well is put on production will give an idea of what the created conductivity is. From these observations subsequent treatments can be designe d with the idea of optimizing the treatments

SUMMARY

1. In order for any acid treatment to be successful it is of the utmost importance that evaluation of a well's performance is linked to formation damage. Other than dealing with the removal or bypassing of formation damage stimulation of a low permeability carbonate is the other situation where an acid treatment might be employed.
2. Knowing where in the life cycle of a well helps in defining potential damage and its extent.
3. It is critical to know the undamaged formation composition and to what extent the treating acid could damage this portion of a reservoir.
4. Pre-Treatment Lab and location testing are critical to a successful treatment.
5. Ensure that execution of the treatment is performed as designed and that complete notes of all events are recorded. Especially important is the recording of events that occurred different than the expected.
6. Evaluate and optimize treatments.

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ACKNOWLEDGEMENTS

The author wishes to thank the management of Baker Hughes for allowing him to write and present this information.

Table 1 – Comparison of Acid Dissolving Power	
Acid	**Pounds of Limestone Dissolved per Gallon of Acid**
15% HCl	**1.84**
15% Acetic	**1.08**
15% Formic	**1.42**
Hydrofluoric Acid is Not Used on Carbonate	

Table 2 – Formation Damage and Sources	
Sources	**Formation Damage**
Drilling	Emulsion
Cementing	Water Block
Perforating	Wettability Alteration
Completion & Workover	Inorganic Deposits – Scales
Gravel Packing	Paraffin and/or Asphaltenes
Production	Mixed Deposits
Stimulation	Bacterial Slime
Injection Operations	Silt and Clays
	Gel Residues

Table 3 – Formation Damage Based on Well Type		
New Well	**Old Well**	**Injection Well**
Plugging Solids	Emulsions	Emulsions
Emulsions	Scale	Scale
Water Block	Organic Deposits (Paraffin and/or Asphaltene)	Organic Deposits (Paraffin and/or Asphaltene)
Wettability Alteration	Polymer Residue	Polymer Residue
Fines Migration	Corrosion	Corrosion
Bacterial Slime	Fines Migration	Fines Migration
Polymer Residue		
Perforation Tunnel Compaction		
Filtrate Effects on Mineralogy		
Polymer Residue		

Table 4 – Base fluid choices formation damage
Hydrochloric Acid
Acetic Acid
Formic Acid
Multi-Carboxylic Acid Compounds
Sulfamic Acid
Xylene
Environmentally Friendlier Solvent Systems

Table 5 –Typical fluid and additive choices per damage	
Treatment Fluid	**Damage**
Solvent plus Penetration Surfactant Systems[1]	Organic Deposition Water Block Acid Sludge Oil Base Mud Filtrate Invasion Emulsion
Acid plus Ionic Stabilizers	Solids Invasion Inorganic Scales Tubing Corrosion Products
Acid plus Suspending Agent	Perforation Compaction Migratory Fines
Acid plus Surface Tension Reduction Additives	Water Base Mud Filtrate Invasion Cement Filtrate Invasion

Table 6 – Example Acid Volume Calculation for a Matrix Treatment	
Wellbore Diameter, inches	8
Penetration of Acid Desired, feet	1.5
Interval Thickness, feet	50
Reservoir Porosity, %	6
Interval Rock Volume, ft^3	480
Volume 15% HCl to Remove 5% of the Rock, gallons	2189
Volume 15% HCl to Remove 15% of the Rock, gallons	6567

Table 7 –Typical Additives	
Function	**Description**
Corrosion Control	Inhibitors and Intensifiers
Iron Control	Reducing Agents, Chelating Agents and Buffers
Non-emulsifiers	Nonionic, Anionic and Cationic
Surfactants	Wettability Adjusters, Fluid Recovery Agents, Penetrating Agents and Suspending Agents
Viscosifiers	Natural Polymers, Synthetic Polymers and Viscoelastic Surfactants

Table 8 – Typical diverters concentrations				
Materials	**Openhole, lbs/ft or gals/ft**	**Concentration, lbs/gal**	**Perforations, lbs/ft or gals/ft**	**Concentration, lbs/gal**
Graded Rock Salt	15 – 20	½ - 2	10 - 15	½ - 1
Benzoic Acid Flakes	10 - 15	½ - 2	5 – 10	½ - 1
Gilsonite	10 - 15	½ - 2	5 – 10	½ - 1
Ball Sealers	----	----	100% Excess	Varies With Rate

Foam	20 – 25	75Q	15 – 20	75Q
Viscoelastic Fluids	25 - 30	Varies With Rate and Temperature	20 - 25	Varies With Rate and Temperature

Table 9 – System choices for acid fracturing treatments[3,4,5,6]

Fluids	**Description**	**Limitations**
Neat or Slick Acid	An acid with bare minimum additives to deal with emulsions, iron control and friction pressure.	This fluid should be used for short fracture and low to moderate temperature conditions.
Blended Acids	Systems where two acids of differing strength are blended. These systems work utilize the reactivity of the stronger acid to react first going into the fracture and the weaker acid to react in the extended portion of the fracture.	These fluids are used primarily in high temperature environments to not only provide deeper penetration but also limit corrosion.
Viscous Acids	These systems use the viscosity of the fluid to limit spending and provide leakoff control so that an created fracture may be etched deeper into a formation. They are viscosified either with polymers or surfactant packages (Viscoelatic).	These systems are used for deep penetrating fracture treatments. Some are limited in temperature of application to 250° to 275°F while others can be used at over 300°F.
Chemically Retarded Acids	These acids are blocked from reacting with the formation by either a hyrocarbon phase or an anionic surfactant. In the case of the two phase system some leakoff control is maintained by virtue of relative permeability.	Either of these systems typically used I wells with high bottomhole temperatures.

Table 10 – Breakdpown of fluid Volumesbased on number of stages

Number of stages	2	3	4	5	6
Volume, %	40	30	19	10	5
	60	33.5	23	15	9
		36.5	27	20	14
			31	25	19
				30	24
					29
Total	100	100	100	100	100

Table 11 – Rate and thickness determine number of stages down 5-1/2" casing

Zone Thickness, ft	Number of Stages					
	Rate, BPM					
	10	20	30	40	50	60
10	1	1	---	---	---	---
20	2	1	1	1	---	---
40	4	2	2	1	1	---
80	6	3	3	2	2	1
160			4	3	3	2
320			5	4	4	3
640			6	5	5	4
1280				6	6	5

Table 12 – Rate and thickness determine number of stages down 2-7/8" tubing							
Zone Thickness, ft	Number of Stages						
	Rate, BPM						
	8	10	12	14	16	18	20
10	1	1	1	1	---	---	---
15	2	1	1	1	1	---	---
20	3	2	2	1	1	1	1
25	3	3	2	2	2	1	1
30	3	3	2	2	2	2	2
35	4	4	3	3	2	2	2
40	4	4	4	3	3	2	2
45	5	5	4	4	3	3	3
50	6	5	4	4	3	3	3

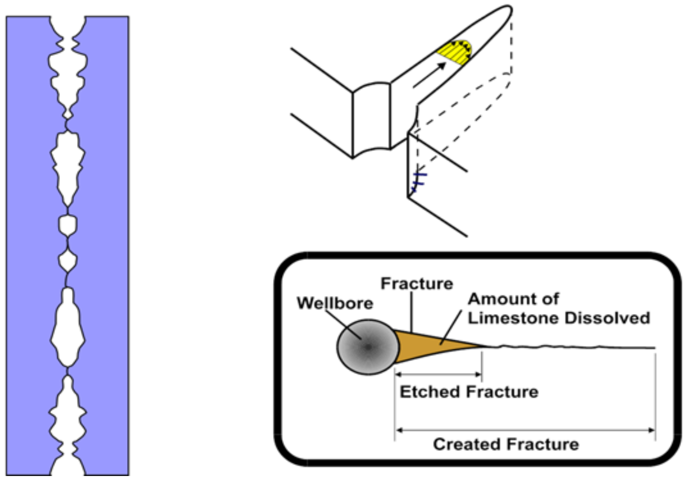

Figure 1 – Illustration of differential etching and created fracture length and etched fracture length

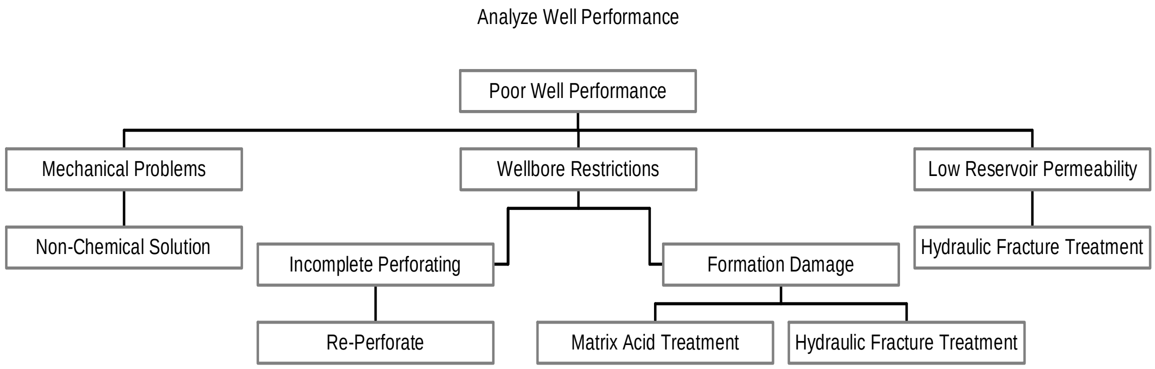

Figure 2 - Decision Tree Evaluating Problems with Production

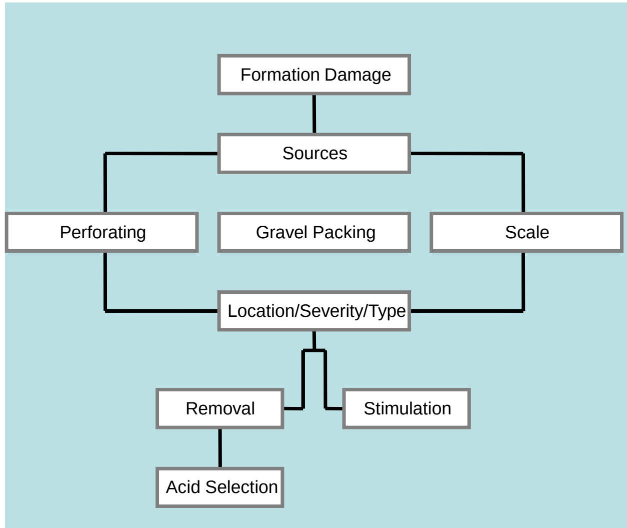

Figure 3 - Decision tree for treatment design to deal with formation damage

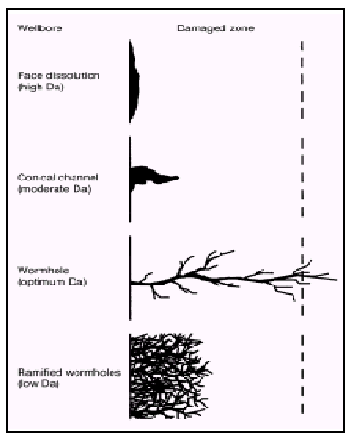

Figure 4 - Examples of rate effects on acid penetration into reservoir

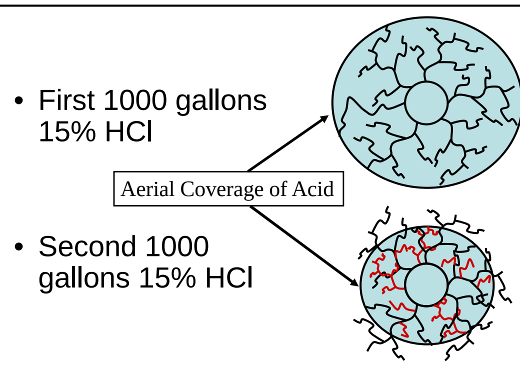

Figure 5 – An illustration of two equal acid treatments on same well

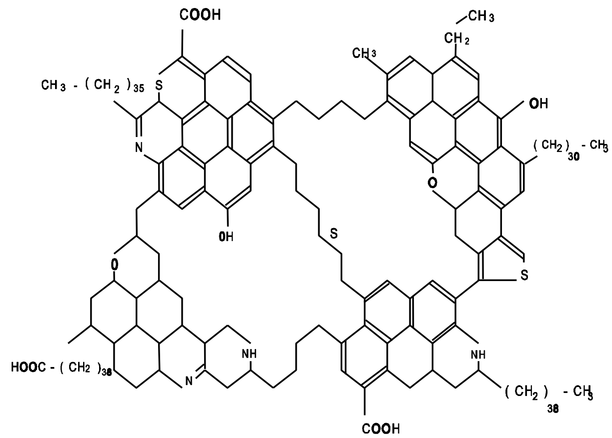

Figure 6 - Example Asphaltene particle chemical structure

Figure 7 – Illustration of acid sludge from San Andres oil and 15% Hydrochloric Acid.

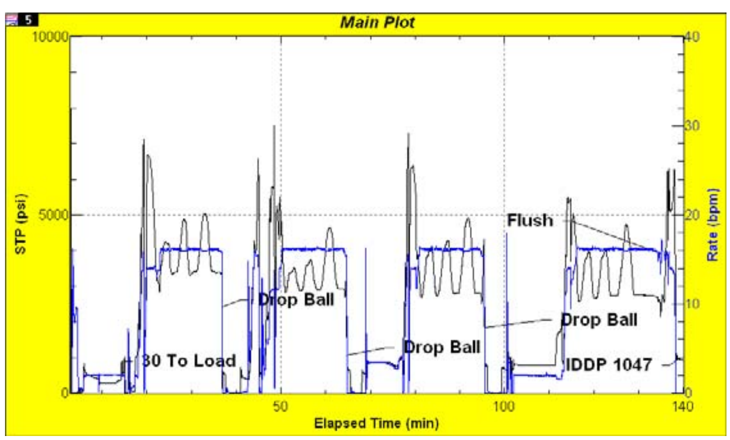

Figure 8 – Rate and Pressure chart of an acid treatment using openhole packers and sliding sleeves on a horizontal well

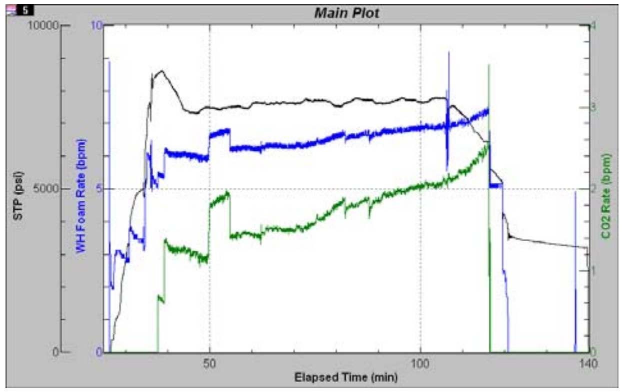

Figure 9 – Rate and Pressure chart of an acid treatment using ball sealers for diversion

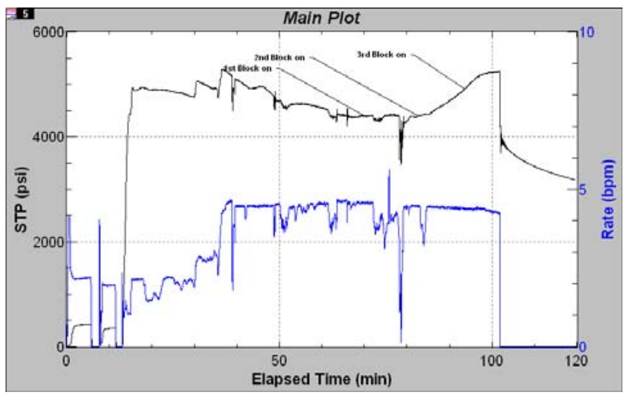

Figure 10 – Rate and Pressure chart of an acid treamtne using Rock Salt

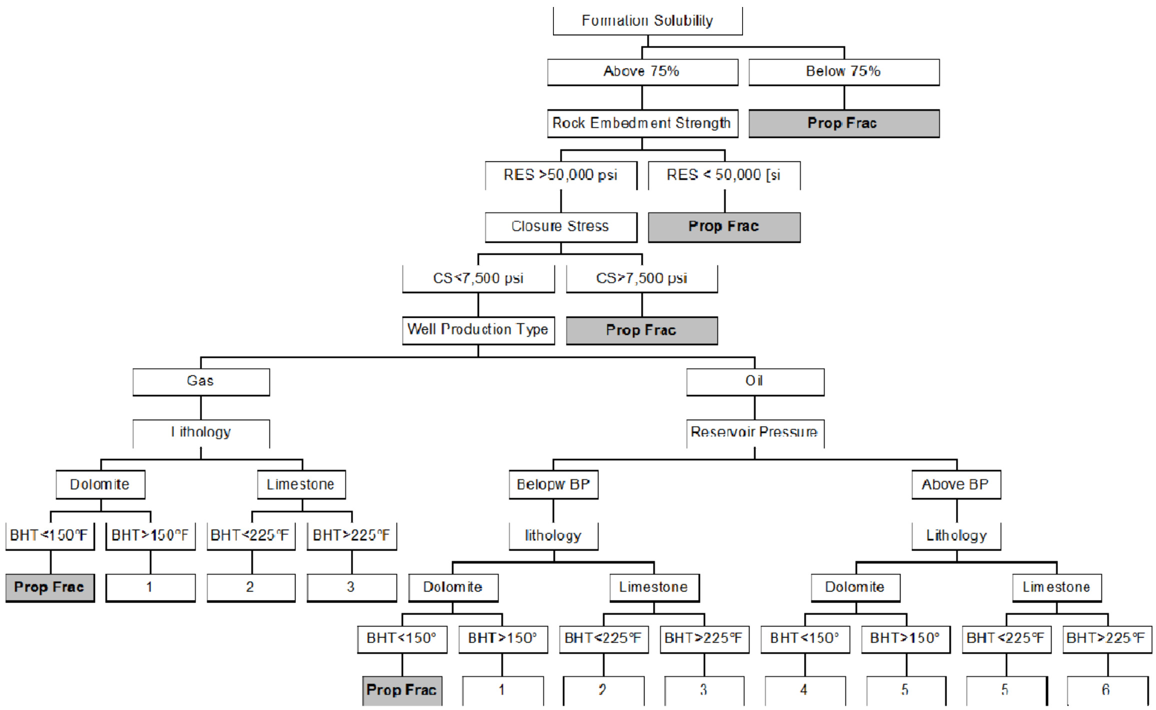

Figure 11 – Decision Tree for Treatments

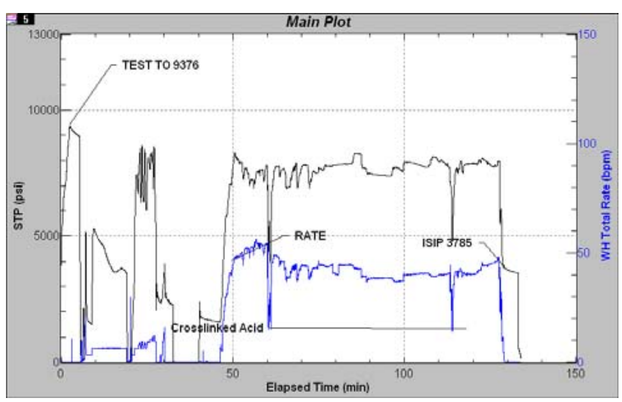

Figure 12 – Rate and pressure chart for an acid fracture treatment pumped down 2-3/8" tubing and the 2-3/8" tubing 5-1/2" casing annulus